STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH ELECTRIC") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) INCLUSION IN ITS BASE RATES OF COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN CERTAIN COSTS AND REVENUES RELATING TO ITS GENERATING FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN NON-FUEL RELATED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MISO") CHARGES AND PETITIONER'S TRANSMISSION REVENUE REQUIREMENT; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS FUEL ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (8) APPROVAL OF THE CLASSIFICATION OF PETITIONER'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN FACTOR TEST; AND (9) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC SERVICE INCLUDING NEW INTERRUPTIBLE AND ECONOMIC DEVELOPMENT RIDERS.	)	FILED FEB 27 2007 INDIANA UTILITY REGULATORY COMMISSION CAUSE NO. 43111

PREFILED TESTIMONY OF

JOAN M. SOLLER - PUBLIC'S EXHIBIT #1

WES R. BLAKLEY – PUBLIC'S EXHIBIT #2

J. RANDALL WOOLRIDGE – PUBLIC'S EXHIBIT #3

MICHEAL J. ILEO – PUBLIC'S EXHIBIT #4

RICHARD A. GALLIGAN – PUBLIC'S EXHIBIT #5

THOMAS S. CATLIN – PUBLIC'S EXHIBIT #6

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

February 27, 2007

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing **Indiana Office of Utility Consumer Counselor's Testimony and Exhibits** has been served upon the following counsel of record in the captioned proceeding by electronic service, with paper copies available upon request, on February 27, 2007.

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VECTREN - ELECTRIC RATE CASE
IURC Cause No. 43111
OUCC List of Witnesses and Exhibits

	Name	Subject	Exhibits
1	Joan M. Soller	Overview Reliability Enhancement GCRA - Generation Tracker Components MISO -MCRA Tracker Components	Attachments JMS-1 to 4
2	Wes R. Blakley	GCRA & MCRA Accounting	Attachment WRB-1
3	J Randall Woolridge	Cost of Equity Capital Structure	JRW-1 to 11, Appendix A
4	Micheal J. Ileo	Depreciation Depreciation	MJI-1 to 5
5	Richard A. Galligan	Cost of Service Rate Design	RAG-1 to 6
6	Thomas S. Catlin	Revenue Requirement Original Cost Rate Base Economic Development	TSC-1 to 32

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	)	
ELECTRIC COMPANY D/B/A VECTREN	)	
ENERGY DELIVERY OF INDIANA, INC.	)	CAUSE NO. 43111
(VECTREN-ELECTRIC)	)	

DIRECT TESTIMONY

OF

JOAN M. SOLLER

ON BEHALF OF INDIANA OFFICE OF
UTILITY CONSUMER COUNSELOR

FEBRUARY 27, 2007

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OUCC Testimony of Joan M. Soller
Cause No. 43111
VECTREN – ELECTRIC RATE CASE

I. INTRODUCTION

Q: Please state your name and business address.

A: Joan M Soller, Indiana Office of Utility Consumer Counselor, 100 N. Senate Avenue, Indianapolis, 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of the Utility Consumer Counselor (OUCC) as the Director of the Electric Division.

Q: Please describe your background and experience.

A: I received a Bachelors Degree in Electrical Engineering from the University of Dayton in 1987. I am a licensed professional engineer in the State of Indiana. I was employed by Dayton Power and Light Company (DP&L), in Dayton, Ohio, from 1984-1987 as a co-op student. I was employed by Ohio Edison Company in Mansfield, Ohio, from 1987-1989 as a Distribution Engineer. I returned to DP&L in 1989 as a Distribution Engineer of System Planning to complete distribution planning and teach distribution engineering training in conjunction with Sinclair Community College through 1995.

I was employed by Hendricks Power Cooperative in Danville, Indiana, from 2000 – 2005, as Manager of Engineering where my responsibilities included distribution planning, reliability coordination, long-term work plan creation, Geographic Information System (GIS) mapping, capital project management and customer policy advisement. I joined the OUCC staff as the Director of the

Electric Division in January 2006.

Q: Have you ever testified before the Commission?

A: Yes.

Q: How did you prepare for this testimony?

A: I reviewed the petition, testimony, numerous data responses, documents and Commission orders from other cases, as well as considerable literature pertaining to Midwest Independent System Operator (MISO) and general utility practices. I also participated in several technical conferences, and toured the AB Brown plant as well as electric transmission and distribution facilities with various staff members of Vectren South Energy Delivery of Indiana (hereinafter referred to as Vectren or Petitioner or the Company).

Q: Please summarize the testimony of the OUCC witnesses in this case.

A. I testify on several issues as outlined in detail below. Mr. Wes Blakley testifies regarding the accounting mechanics of Vectren's proposed generation and MISO trackers. Dr. J. Randall Woolridge testifies on the cost of capital and the return on equity. Mr. Michael Ileo testifies about the depreciation rates and expenses. Mr. Richard Galligan testifies on issues concerning the Company's cost of service study and rate design proposals. Finally, Mr. Thomas S. Catlin testifies on the determination of the revenue requirement and accounting issues.

Q: What is the purpose of your testimony?

A: I evaluate Vectren's proposed Energy Delivery Operations programs. I also make recommendations regarding proposed Reliability Enhancement Programs related to transmission and distribution assets and technology improvements. I critique

Petitioner's inclusion of specific components in the proposed Generation Cost and Revenue Adjustment (GCRA) and MISO Cost and Revenue Adjustment (MCRA) tracking mechanisms. Finally, I address Vectren's proposal to use a return of equity test in lieu of the net operating income test for purposes of the FAC Earnings Test.

Q: Please describe the OUCC's general observations in this case.

A: The OUCC acknowledges the Company's reference to changes in the electric industry in general, and specifically to its own situation since its last rate case order in 1995. The merger between Southern Indiana Gas and Electric Company (SIEGCO) and Indiana Gas to become Vectren Corporation, evolution of the MISO energy market, changing employee demographics, and rising costs have all significantly impacted the Company's operations. While my testimony may appear to depart from the OUCC's prior practice of not addressing operational issues in great detail, my operational and management experience in the electric industry provides an opportunity to include several suggestions that the OUCC believes will be helpful to Vectren's overall operations. I believe these suggestions were well received by Vectren during our discussions over the last six months and viewed as constructive to the process.

The OUCC reviewed the requested adjustments to revenue and expenses and related workpapers in great detail. On occasion we found inconsistencies between the dollar amount listed for adjustments and the calculation descriptions in workpapers. While some of these have been addressed, others which remain unresolved are explained in my testimony.

II. OPERATIONS AND MAINTENANCE ENHANCEMENT PROGRAMS

Q: Please summarize the OUCC's position generally on Vectren's proposed plan for systematic maintenance.

A: While the OUCC encourages Vectren to update and improve its maintenance practices, it should implement these programs more gradually. The evidence suggests that Petitioner has not implemented a systematic preventative maintenance plan since its last rate case. We believe the Company should first complete its Energy Delivery System planning studies before it undertakes comprehensive programs. Once the maintenance improvement plans are implemented, the OUCC requests that Vectren file periodic reports to update the Commission and the OUCC on the progress of the system improvements. Finally, the OUCC recommends that service quality benchmarks be created to track whether the programs are having the desired effect.

ENERGY DELIVERY OPERATIONS PROGRAMS

Q: What is the OUCC's understanding of the Vectren programs described in this proceeding?

A: It appears that Vectren has made significant strides to identify areas where system facilities and operational procedures need to be improved to maintain system integrity, maximize existing investments, and improve or upgrade facilities. The Company outlined plans to add line-specialist personnel, improve work practices, establish disciplined programs, and utilize technology to improve reliability and enhance customer service[1]. Generally, the OUCC supports Vectren's efforts to

[1] See Petitioner's Exhibit No. EJS-1 page 3 of 21 lines 3-13.

improve current practices related to operations and maintenance (O&M); however, some of them appear to be overly aggressive when compared to industry standards and its resources. Since Vectren's last electric rate case in 1995, it appears that Vectren has performed only minimal reactive maintenance practices and virtually no preventive or proactive measures. From discussions with Vectren staff and personal field observations I can identify several examples of the Company's inadequate maintenance practices. These include substation inspections, equipment painting, and line clearance. Regular substation site inspections to ensure public safety have occurred, but circuit breaker counter readings and interval maintenance have not been performed or documented consistently. No regular substation equipment painting has occurred in the last 15 years. While Vectren completes transmission line clearance, there is no systematic line clearance program for distribution circuits. Vectren has trimmed or removed trees when service interruptions have occurred, but has not focused on a multi-year cycle to proactively reduce these interruptions.

Q: Generally, what does the OUCC recommend?

A: The OUCC suggests the Company evaluate their plans to implement preventative maintenance program improvements more gradually. Many years have passed since regular maintenance improvements have been initiated, therefore we expect proposed improvements to span several years as well, to allow the Company to avoid "biting off more than they can chew" while managing the impact of related expenses on ratepayers. The OUCC recommends reducing the scope and resource allocations of several programs to reflect industry practice, reasonable planning, and realistic management responsibility.

Q: What specific support does Vectren offer for its Program?

A: In many instances, Vectren staff refers to a 2005 UNDERWRITING RISK ASSESSMENT report published by AEGIS[2] to explain the origin of inspection data for proposed programs. However, there is no substantial engineering analysis included in this report which instead focuses on risk management.

In addition to undertaking significant maintenance programs, Petitioner witness Schach describes plans to complete two engineering studies including an ***Electrical System Master Planning Study*** and ***Electrical System Protective Device Coordination Study*** to identify load flows, circuit improvement needs, load growth, and assess the status of protective coordination[3].

Q: What is your opinion of the process Vectren has chosen to address its maintenance needs?

A: Based upon my years of experience in Electric System Planning, good utility practice would be to complete these types of studies **prior** to recommending maintenance work on specific circuits. A thorough review of conductor capacities, maximum fault currents, protective equipment limits and settings, substation transformer loading, reactive power ranges, and anticipated growth are all factors which should be considered in these types of studies which impact maintenance recommendations.

This could, at times, minimize field time by avoiding redundant trips. For example, if a recloser bank that was undersized or incompatible with other circuit protective devices was identified, an engineer could specify that a technician

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[2] See Public's Exhibit CSX-14, which was admitted into evidence in this case-in-chief hearing on December 13, 2006.
[3] See Petitioner's Exhibit No. EJS-1, page 21 of 21, lines 3 to 24.

modify equipment settings while inspecting it. . Specifically, I suggest the Company consider completing these studies prior to implementing enhanced programs such as the ***Protective Device Fuse Correction***, or the ***Circuit Line Patrol*** and ***Overhead Inspection Program*** for specific equipment, described in its workpapers.[4]

Given the large scope of planned programs, the OUCC suggests the Company consider focusing its program efforts on a specific substation or specific circuit basis to realize the maximum benefits of system impacts and lessons learned systematically. For example, if line clearance, circuit line patrols, pole inspections, guying and grounding inspections, and equipment inspections are accomplished on a substation basis, favorable results may improve reliability which may be measured through decreased service interruptions.

RELIABILITY ENHANCEMENT BENEFITS

Q: **What measures could be implemented to help track whether Petitioner's programs enhance system reliability?**

A: The OUCC suggests the Company provide periodic reports to the Commission and the OUCC regarding (1) staffing levels achieved, (2) specific program progress and (3) a summary of the benefits of these reliability enhancement programs to ensure that the revised pro forma adjustment dollars actually are spent where they are allocated and accomplish the goals of improving service. Service quality benchmarks such as SAIDI, SAIFI and CAIDI[5] would be effective tools for measuring improvements. Customer Satisfaction surveys geared toward

[4] See Electric MSFR -3680-170 and 172 of 1050.

[5] These indices are commonly used in the electric utility industry to measure reliability, including System Average Interruption Duration Index, (SAIDI), System Average Interruption Frequency Index, (SAIFI) and Customer Average Interruption Duration Index, (CAIDI).

service quality or tracking customer complaints may also be appropriate tools.

Q: How would your proposal differ from the Company's current practice of reporting service quality indices to the Commission annually?

A: The OUCC envisions more detailed reporting than the overall Company indices which are reported annually and our plan would include informal meetings between the Petitioner, the Commission and the OUCC to discuss results. The OUCC has had discussions with Vectren staff regarding reporting options and look forward to continuing this dialogue. We recommend creating service quality benchmarks, taking into considerations the unique qualities of Vectren's service territory to measure O&M improvements. The service quality benchmark audit and report could be similar to that used by IPL and the OUCC in the settlement agreement in the IURC Service Quality Investigation of 2001, Cause No. 41962. (See final order and post order compliance filings.) We are not suggesting that Vectren has an unsatisfactory service quality record. However, service quality benchmarks are increasingly being used across the country to track a continuity of reliable service and could create an incentive to Vectren to follow through with the ambitious reliability enhancement programs it has proposed.

Q: Which Vectren programs does the OUCC consider most closely related to Reliability Enhancement?

A: The OUCC suggests the following specific programs be included:

1. Substation Inspections and Maintenance
2. Overhead and Underground Maintenance Programs
   - Reliability Review – Engineering
   - Poor Performing Circuit Patrols
   - Pole Inspections
   - Guy and Ground Inspections
   - Substation Breaker maintenance
   - Infrared Inspections
   - Underground Inspections

3. Transmission Improvements

Q: What Does the OUCC envision progress reports to include?

A: Progress reports may include descriptions of maintenance program components, a tabulation of actual tasks completed, maps indicating progress, a summary of lessons learned and action items for the next period. Regular reports may be delivered annually or semi-annually during informal technical sessions to enhance understanding and expectations among parties.

III. SPECIFIC PROPOSED MAINTENANCE PROGRAMS

Q: Please summarize the OUCC's opinion about specific maintenance programs proposed by Vectren.

A: The OUCC is not attempting to second guess the management decisions of the Company. However, we recommend several modifications to specific plans, due to several factors such as (1) insufficient information provided to justify the expense; (2) inconsistencies between the testimony, the workpapers and informal conversations with staff; and (3) inconsistencies between the proposal and good utility practice. With respect to Vectren's request for additional personnel, the OUCC contends that the evidence does not support the need for the number of new employees requested by the Company. The OUCC agrees that the Company needs to address the aging workforce issue and offers some alternatives which we believe are more in keeping with good utility practice as well as sound ratemaking treatment.

SUBSTATION PROGRAMS

Q: What revenue requirement adjustments do you recommend for Vectren's

proposed Substation Inspection Programs?

A: The Company's proposed substation program components include (1) inspections of distribution and transmission breakers which Vectren defined in workpapers[6] as "deferred from 2005", (2) infrared inspections, (3)substation painting based on a 10 year cycle, (4) maintenance for the distribution Supervisory Control and Data Acquisition (SCADA) system, and (5) completing safety related initiatives recommended by the aforementioned AEGIS report. (See TSC-19 for a summary of the adjustments to these pro forma expenses.)

Q: Please discuss Petitioner's plan for breaker maintenance.

A: Review of Petitioner's testimony does not provide any description or justification for including the "deferred" breaker maintenance. Also, I understand from discussions with Vectren staff that the breaker quantities listed in the workpaper related to this adjustment are incorrect[7]. The number of distribution breakers is cited as 39; but, in fact, there are 139 breakers in service. In addition, the number of transmission breakers cited is 110; however, there are 119 of these breakers in service. Breaker manufacturers typically recommend maintenance on a multi-year cycle or the number of operations exercised by a particular device[8]. Despite discussions I've had with Vectren staff, the Company has not provided any engineering analysis to support their plans to perform such maintenance, therefore the OUCC recommends disallowing this expenditure of $389,495.

Q: Please discuss Petitioner's proposal to perform infrared scans at its substations annually.

A: The Company describes an infrared inspection program to perform thermal scans

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[6] See Electric MSFR 3680 – 164 of 1050
[7] See Footnote 6.
[8] See Attachment JMS-1, pamphlet from Cooper Power Systems at www.cooperpower.com.

at all substations twice annually. The detail provided in the workpaper for this component reflects a cost of $50,000, but the Company claims an incremental expense of $62,500.[9] Therefore, I decreased the amount by $12,500 to disallow this adder. Based upon my industry experience, annual inspections are sufficient so long as there are procedures in place to correct "hot-spots" which are detected through the inspection process in a timely manner. For this reason, I recommend a further decrease in the allowable expense by 50% or $25,000.

Q: Please discuss Petitioner's plan for substation equipment painting.

A: Given the large scope and financial impact of maintenance programs planned by the Petitioner, the OUCC recommends extending the substation painting cycle from every 10 to every 15 years to implement this initiative gradually. This results in a $150,000 decrease to this pro forma adjustment. Since this painting has not occurred for the past 15 years, equipment to be painted should be prioritized based on age, duty cycles and in conjunction with the master long-range plan. That is, the maintenance schedule should minimize painting of equipment which is expected to be upgraded due to load growth.

Q: What do you recommend regarding the Petitioner's plans to maintain the distribution SCADA system and complete recommended safety related tasks recommended in the 2005 AEGIS report?

A: The adjustment for $10,484 for SCADA maintenance is reasonable based upon my observation of the relatively small percentage of substations which contain distribution SCADA capability of 13%. The combined estimated cost of $93,100 to install DANGER signs and remove climbing aids near fences over a three-year

[9] See Footnote 6.

period and inspect fire extinguishers annually is supported by AEGIS data.

OVERHEAD AND UNDERGROUND PROGRAMS

Q: What recommendations do you have regarding Underground Facilities Maintenance?

A: Mr. Schach refers to annual maintenance in his testimony[10], however, workpapers support a 3 year cycle for network facilities and a 5 year cycle for residential facilities, which is consistent with industry standards. The only recommended adjustment is the exclusion of internal labor expenses highlighted by Mr. Catlin. (See TSC-13.) The OUCC would like to see annual progress reports from Petitioner regarding this maintenance program

Q: What does your analysis of the Line Clearance Expense reveal?

A: The recommended 5 year cycle for a distribution line clearance program is conservative and appropriate at this time. Many companies employ 3 or 4 year cycles depending on the availability of resources. The only recommended adjustment is the exclusion of internal labor expenses highlighted by Mr. Catlin. (See TSC-20.) Again, the OUCC recommends that Petitioner submit annual progress reports regarding this program.

Q: What adjustments do you recommend to the proposed Overhead Facilities Maintenance?

A: Overhead programs proposed include circuit and pole inspections, a joint-use pole attachment audit, transmission signage and tower painting, and a proposal to hire ten additional line specialists. Please see Exhibit TSC-21 for a summary of recommended adjustments which total a reduction of $1,433,503 compared to the

[10] See Petitioner's Exhibit EJS – 1, page 9 of 21, lines 26 to 33.

Petitioner's proposed adjustments reflected in schedule A36 which totals $3,147,633.

CIRCUIT AND POLE INSPECTIONS

The Company claims an incremental expense of $1,492,800 in the "Overhead Reliability Program", to perform complete inspections of its 5 worst performing circuits at a cost of $100,000 each[11]. Discussions with Vectren staff reveal that "5" should be "5%", which results in the inclusion of 12 circuits. In response to Q-123, (UCC-123), Vectren indicated the majority of this expense was related to contract labor at $1,468,800 with an additional $24,000 included for materials. Given the fact that a non-detailed estimate of $100,000 per circuit appears to have been used, the OUCC recommends this amount be reduced to $1,200,000.

The Petitioner includes an incremental expense of $179,143 per year for pole inspections; however, the workpaper details only support $80,000 per year for 10 years.[12]

Discussions with Vectren staff revealed an internal decision to modify specific pole procedures between the time the initial costs were estimated and their case filed, so the inconsistent data remains. There are several ways to accomplish pole inspections ranging from visual inspections to sound tests to excavation of several inches of earth around the base of a pole followed by

[11] See Electric MSFR 3680 – 170 of 1050.

[12] See Footnote 11.

chemical injections to protect them against rotting.[13] Originally, Vectren planned to complete a sound and bore test to determine pole conditions at an estimated cost of $7 per pole. They have since decided they want to use an excavation and treatment procedure instead, which is estimated to cost approximately $15 per pole. Based on the original value of $80,000 annual expense for $7 per pole, approximately 11,428.6 poles will be inspected per year. The dollar values listed in response to Q-123 (UCC-123) indicate $172,465 for contracted expenses for this program, which is in-line with $15.09 per pole. While the OUCC believes systematic pole inspections are in the public interest, we gain a sense of making the numbers work post-filing for this adjustment. Perhaps the Company can clarify its plans and derivation of these costs more clearly in revised workpapers. They have included internal labor and overheads amounting to $6,678, which should be eliminated, as no new personnel have been requested as cited by Mr. Caitlin. (TSC-21)

Q: **Please discuss the Petitioner's proposal to perform Infrared Inspections.**

A: The Company claims an incremental expense of $100,000 per year to perform thermal scans on all mainline distribution circuits; however, the workpaper details reveal an estimated expense of only $48,000[14]. Inspecting circuits every year is unnecessary. I suggest inspecting areas where potential overload conditions may occur due to the aforementioned master long-range plan as well as a 2 or 3 year cycle for the overall system. I have reduced this pro-forma expense by 50% or

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[13] See "Pole Maintenance and its Role in Pole Life Extension," by Tim Carey published in Electricity Today at http://www.electricity-today.com/et/apr00/pole.html.

[14] See Footnote 11.

$24,000. (TSC-21)

The Company claims an incremental expense of $40,000 per year to perform thermal scans on all transmission switches; however, the workpaper details only support an estimated expense of $26,000. I have recommended a reduction to this pro-forma expense to reflect $26,000. (TSC-21)

Q: Please discuss the Petitioner's proposal to complete Overhead Inspections of Line Equipment.

The Company claims an incremental expense of $24,000 to perform overhead equipment inspections for regulators, capacitor banks, and reclosers, all of which utilize internal labor according to Q-123 (UCC-123). As cited by Mr. Catlin, these costs are already included in Ms. Hardwick's A21, so they have been excluded. (See Public's Exhibit 6, Testimony of Thomas S. Catlin, page 15, lines 6 to 13.)

Q: Please discuss the Petitioner's proposal to complete additional Flyover Inspections.

A: The Company claims an incremental expense of $25,000 for flyover inspections to double the frequency to accomplish them quarterly. The OUCC understands these have been completed twice annually at an expense of $25,000 per year since 2003. There is no support for the need to increase the frequency of this activity; therefore, the additional $25,000 has been eliminated. (TSC-21)

Q: Please discuss the Petitioner's proposal to initiate a Pole Attachment Program.

A: The Company plans to implement a Pole Attachment Program to contract joint-use pole audits in the field. They claim an incremental expense of $62,720 to accomplish this work; however workpaper details reveal an estimated cost of $100 per pole for 500 poles per year, which would amount to $50,000 annually[15]. Discussions with Vectren staff revealed a change in their calculations that was not reflected consistently. According to staff, the original estimate of 500 poles per year was adjusted internally to only 784 to reflect an actual 12 month experience. I am not certain if this was in the test year. In addition, staff believed they could negotiate a lower cost of $80 per pole due to the increased volume, which they used to arrive at a total cost of $62,720.

The OUCC proposed some options to utilize existing contractors such as those who perform underground locating in response to "Call Before You Dig (811)" requests to reduce costs by minimizing contractor's travel time. In addition, the OUCC expects revenues to increase due to successful identification and billing of undetected joint-use. Therefore, we reduced the pro-forma expense to reflect the initial estimate of $50,000. (TSC-21)

Q: Please discuss the Petitioner's proposal to complete a Transmission Tower Painting Program.

A: The Company plans to implement a Transmission Tower Painting Program at an estimated contractual expense of $250,000 per year based on a 5 year cycle. It is unclear why this painting cycle is more aggressive than the proposed substation equipment program since the likelihood of electric flash-over or service interruptions is less on individual structures than within substations. In response to Q-281 (UCC-281), the Company cites discussion with one other utility about

[15] See Footnote 11.

the time interval of this program, which chose to use a 20-year cycle, which is reasonable. The adjusted annual cost of $62,500 per year results in a reduction of $187,500 to the pro forma expense. (TSC-21)

Q: Please discuss the Petitioner's proposal to complete a Pole Guy/Ground Inspection Program.

A: The Company plans to implement a Pole Guy/Grounding Inspection program at an estimated contract cost of $301,428. The workpaper detail shows an estimated cost of $83,200.[16] The OUCC has discussed this discrepancy with Vectren staff, but has not received a response describing why it exists; therefore I have reduced the pro forma expense by $218,228, to reflect $83,200. (TSC-21)

ADDITIONAL PERSONNEL RELATED TO O&M

Q: What is your understanding of the Company's request to hire 10 additional Line Specialists to perform needed O&M work?

A: Based upon my review of Mr. Schach's testimony and discussions with Vectren staff, I understand the Company's goals in hiring 10 additional staff are two-fold: to complete needed O&M work and reverse the current ratio of contracted to internal labor to improve customer service. While the OUCC commends the Company's proactive approach to solve potential problems related to crew availability, we do not see adequate support for this number of people, at an estimated annual expense of $472,544.[17]

Q: Please explain.

A: The OUCC considered the programs proposed by the Petitioner which Line

[16] See Footnote 11.
[17] See Petitioner's Exhibit EJS-1, pages 14 to 18 and Electric MSFR – 3680-170 of 1050

Specialists may accomplish, such as, overhead reliability inspection, pole, guy and grounding inspections. We discussed comparing the estimated hours needed to accomplish them to average hourly wages to arrive at a reasonable estimate of internal resources needed with Vectren staff. The OUCC understands that the Petitioner does not plan to use the new line specialists to reduce contracted resources for these programs. Vectren has not identified additional programs such as expanding maintenance or completing a full field inventory of all construction property for these new employees to accomplish or quantified an increase in capital work which is driving a need for additional resources.

Several customers shared personal concerns at the January 9, 2007, public field hearing regarding contracted personnel who are not familiar with their neighborhoods when responding to trouble calls. In response to these concerns and to support a gradual effort to increase company labor to mitigate risks of contractor unavailability, the OUCC recommends the Petitioner's adjustment be reduced to reflect three (3) new Line Specialist Apprentices.

The OUCC suggests the Petitioner consider the use of line apprentices to complete some of maintenance inspections as part of their training program. We understand through discussions with Vectren staff that the Company is in the process of negotiating a new contract with the local International Brotherhood of Electrical Workers (IBEW) business unit and we suggest it considers how union work rules may effectively reflect technological changes and possibly use apprentices to complete safety appropriate tasks such as inspections.

Please see TSC-21 which reflects a decrease of $330,779, to reflect 3 of the 10 requested additional line specialist apprentices who will have 70% of their time allocated to O&M.. The resultant amount remaining for this adjustment of $141,763, is based on dividing the total adjustment of $472,542 by 10 to arrive at an estimated cost per person, then multiplying by 3. It is not clear how the average hourly rates of $21.66 and $22.28 listed as support in workpapers were used to arrive at the overall adjustment number by the Petitioner, but this approach appears reasonable.[18]

The OUCC recommends the previously mentioned Reliability Enhancement Report reflect actual staffing realized as well as customer service benefits of these additional resources.

Q: Please discuss the Petitioner's proposed Reliability Studies and Planning for engineering support.

A: The OUCC supports the Company's efforts to assess its electrical system condition and plan for long-term growth. The use of contracted services is an efficient way to complete the analysis in a timely manner prior to initiating O&M programs. The projected cost of 85,000 per year, for a 3-year period is reasonable. The need to continually update the plan might be better accomplished by a full-time staff engineer. In addition, cooperative education students requested would be an excellent resource to complement these efforts. Mr. Catlin will address the adjustment for internal labor in his schedule TSC-13.

TRANSMISSION IMPROVEMENTS

[18] See Footnote 11.

Q: What is the OUCC's understanding of the Company's planned transmission projects?

A: Petitioner's witness Chambliss describes specific transmission projects intended to improve the import capability in response to increasing demands on the Midwest Independent System Operator (MISO) transmission system. The OUCC is aware of the Petitioner's active participation in system modeling and planning efforts with MISO stakeholders and encourages this collaboration to continue. Transmission projects undergo a prudency review before they are included in the MISO Transmission and Expansion Plan (MTEP).

Q: What evidence has the Company provided to illustrate the benefits of the MISO market and operation of the transmission grid?

A: In response to Q-277 and Q-278 (UCC 277 and UCC 278), the Company provided information related to Transmission Loading Relief (TLR) activity since 1999. TLR events indicate when transmission balancing authorities are directed to reduce transmission loading to relieve congestion on individual or multiple system components. Since the initiation of the MISO Day 2 markets, dispatchers are able to reduce the number of TLR events through modifying generation and transmission constraints in tandem to result in efficient system operations. In response to Q-278, (UCC-278) the Company provided the number of incidents recorded by National Electric Reliability Council (NERC) in its control area which are shown in the table below.

Year	Number of TLR Events
1999	3
2000	8
2001	n/a
2002	11
2003	5
2004	43
2005	30
2006	16

We note that while many factors affect transmission operations, since MISO acquired control in 2004, the number of TLR events has steadily declined.

USE OF TECHNOLOGY

Q: You mentioned the Company's plans to utilize technology. Please describe what these plans include.

A: The Company describes implementing an Asset Management Transformation (AMT). This multi-phase project will integrate many Information Technology (IT) systems such as Geographic Information System (GIS) Mapping, Customer Information System (CIS), property unit and work order accounting, meter service orders, work order engineering, and time reporting. I understand Vectren plans to populate mobile work stations to enhance the decision-making ability of field personnel, facilitate field data collection, reduce radio communications and back-office processes, and ultimately reduce response time to customers.

Q: What costs are ratepayers absorbing for AMT?

A: The OUCC understands that electric ratepayers have been absorbing and will continue to absorb an allocated portion of development costs of internal IT and operations staff to develop procedures, compile data, integrate software systems and manage this project. The actual capital expenses are absorbed by Company shareholders.

Q: What concerns do you have regarding AMT?

A: The Company's plans to implement AMT appear to be well planned and consistent with industry recommendations. Mr. Schach cites an expected savings in O&M expenses of $35,000 per year based on improved meter order scheduling. Upon full deployment of the integrated mobile systems, the OUCC expects operational savings to be much greater. A cost-benefit analysis, similar to that I referenced in testimony filed last month in IURC Cause No. 43083 for the deployment of Advanced Metering Infrastructure (AMI) would likely produce much higher cost-savings in after-hours response, over-time labor expenditures, vehicular fuel from reduced miles traveled, clerical labor and reduced customer complaints. Perhaps a rate review in 5 years would be appropriate to asses the actual cost savings due to increased efficiencies.

IV. COST RECOVERY TRACKERS

Q: Please summarize the OUCC's position on Vectren's proposed cost recovery trackers.

A: Petitioner has requested authority to create two new trackers through which it can track and recover costs. The Generation Cost and Revenue Adjustment Tracker (GCRA) is a multi-expense tracker. The scope is quite broad but it contains six components which have been tracked by other Indiana utilities. The seventh component, Environmental Chemical Costs, is more fully discussed in OUCC witness Blakely's testimony and we oppose its inclusion in this tracker. It is purely an operating expense and its inclusion constitutes single issue ratemaking. Other than that item, the OUCC does not oppose the creation of this tracker so long as it is modified as discussed in some detail below.

The second tracker proposed by Vectren is the MISO Cost and Revenue Adjustment tracker (MCRA). Generally, the OUCC supports the creation of the MCRA with respect to the recovery of MISO Charges Component (MCC) as discussed more fully below and in Mr. Blakely's testimony. However, it is our opinion that the MISO Transmission Component (MTC) should not be implemented in this tracker at this time. There is simply insufficient information available to track these expenses. The OUCC suggests that perhaps Vectren could seek to defer recovery of these expenses until such time as actual experience with them provides better information with which the Company, the Commission and other interested stakeholders can make informed decisions.

GENERATION COST AND REVENUE ADJUSTMENT (GCRA) TRACKER

Q: What is the OUCC's understanding of Vectren's proposed GCRA tracking mechanism?

A: The Company has proposed a tracker comprised of seven components to account for generation expenses and related revenues which they cite as variable, volatile and outside of its control. These include the following:

1. Wholesale Sales Credit for Off-System
2. Firm Municipal Contract Sales Credit for 2007
3. Demand Costs for Purchased Power
4. Environmental Chemical Costs
5. Interruptible Sales Credits to Customers
6. Direct Load Control Credits
7. Environmental Emission Allowances

Q: Please describe the OUCC's recommendations regarding this tracker and its components.

A: While the tracker encompasses production based items, its scope is quite broad. Overall, six of the seven requested components have been tracked by other Indiana utilities. Mr. Blakley will address the OUCC's position that environmental chemical costs should not be tracked and the remaining elements should be separated between DSM and reliability issues similar to Duke Indiana's mechanisms. I will address each component separately.

First, the **Wholesale Sales Credit** proposal includes a 50/50 sharing arrangement of off-system sales margins between jurisdictional customers and Company shareholders above or below a target of $10.5 million. This target figure was based on actual sales to MISO during the test year. Currently, jurisdictional customers receive 100% of the representative wholesale sales reflected as a credit to revenue requirements in base rates, while Vectren shareholders are at risk and/or reward for deviations therefrom[19]. Therefore, the OUCC believes this 50/50 sharing arrangement is too generous to shareholders while jurisdictional customers assume all O&M expenses and 100% of rate base. The OUCC proposes a 90/10 sharing arrangement (90% to ratepayers) which should be sufficient to incent the Company to operate the power plants efficiently and maximize investments.

The **Firm Municipal Contract Sales Credit for 2007** reflects the expected credit of $13.68 million in 2007, which is the last year for which the

[19] Vectren's non-firm wholesale margins embedded in rates are under $1 million. For the test year period ended March 31, 2006, Vectren experienced non-firm wholesale margins of $16 million. (See Petitioner's Exhibit RGJ-1, page 14, lines 9 to 11.)

Company is committed as a long-term power supplier. Witness Jochum explained in testimony and in several technical conferences, that the exclusion of future fixed contracts is reasonable given the fact that jurisdictional peak demand is increasing. This position is consistent with the Vectren 2005 Integrated Resource Plan. The OUCC expects the absence of long-term contracts, currently at the 100 MW level, will likely result in additional wholesale sales to MISO.

The approximate $4.3 million value given as a reference for **Demand Costs for Purchased Power** is based on active agreements with the Ohio Valley Electric Corporation (OVEC) and Duke Vermillion facilities and seems reasonable. These will vary according to escalation factors built-into existing contracts. Their inclusion in a tracking mechanism is consistent with the Duke Rider 70 reliability tracking mechanism. The ability of the OUCC and the Commission to challenge the prudency of future demand costs for purchased power should be retained in future cost recovery proceedings.

The OUCC believes the **Environmental Chemical Cost** included in base rates should be adjusted from the approximate request of $16.4 million to $14.4 million as explained by Mr. Catlin and does not agree with the request to track these expenses associated with pollution control equipment which is in service at the time of this rate case. Please see Public's Exhibit 6, testimony of Thomas S. Catlin, pages 20 and 21, TSC-17, TSC-18, and Public's Exhibit 2, testimony of Wes R. Blakley, pages 5 and 6 for further discussion of this topic.

The OUCC supports the inclusion of **Interruptible Sales Credits to Customers** for Commercial and Industrial (C&I) customers as consistent with

Duke's Rider 70 and a cost-effective Demand Side Management (DSM) option. The actual annual expenses for these credits may vary dramatically based on weather and loading conditions from the reference value of approximately $1.1 million.

The **Direct Load Control Credits** are appropriately tracked through the DSM mechanisms by IPL and Duke as a cost-effective DSM option. The OUCC is actively involved with Company staff, the Citizens Action Coalition and a third-party consultant to identify a Vectren-specific DSM and Energy Efficiency Action Plan. Through discussions with Vectren staff, the OUCC understands that the reference value of approximately $0.9 million is based on current participation levels of approximately 40,000 air conditioning and water heater switches. If or when similar DSM measures are proposed, the OUCC expects discussions and a joint filing to propose any changes to the scope of this existing direct load control program and any related cost recovery.

The **Environmental Emission Allowances** described by the Petitioner include SO2 and NOx allowances which have been tracked as part of its Operating Expenses Recovery (OER) tracker pursuant to the Multi-Pollutant Settlement in IURC Cause No. 42861. Providing a mechanism to allocate all credits for emission allowances to jurisdictional ratepayers is reasonable since they have funded the environmental capital projects.

MISO COST AND REVENUE ADJUSTMENT (MCRA) TRACKER

Q: What is the OUCC's understanding of the proposed MCRA tracking

mechanism?

A: The Company's proposed tracker to recovery costs associated with the operation of the Regional Transmission Operator (RTO) is patterned after the Commission's approved treatment for Duke's costs through its Rider 68 mechanism. The MCRA contains two components described as MISO Charges Component (MCC) and MISO Transmission Component (MTC). The MCC, as proposed, will include administrative non-fuel charges which will be tracked as they vary from spending levels in base charges related to the time period in question. The second component, MTC, as proposed, contains incremental operating and capital transmission costs and revenues in reference to values in base rates.

Q: How will MISO charges in the MCRA relate to those recovered through the FAC?

A: As a result of several technical teleconferences and informal data requests related to the MCRA, the Company provided a summary of the rate treatment requested for charges billed by MISO which comprise Attachments JMS-2 and JMS-3. Attachment JMS-2 is sorted by charge numbers while Attachment JMS-3 is grouped by requested "Rate Case Treatment". The charges listed as MCRA will be included in the MCC component. Of the eight charges identified, five are administrative in nature, including the new Schedule 26, while three reflect the charge known as Schedule 24.

Q: What is the nature of Schedule 24?

A: Schedule 24 was established by MISO to identify and allocate the balancing authority operating expenses required for participation in the Day 2 energy market. MISO implemented this charge beginning June 1, 2006. My understanding is that these expenses did not exist prior to that time. Schedule 24 is allocated for both the Day-Ahead and Real-Time markets, and distributed in Real-Time.

Q: How does MISO allocate Schedule 24 charges and credits to the Company?

A: MISO allocates Schedule 24 charges and distributes credits to the Company based on the total load in the operating zone.

Q: What is Schedule 26?

A: Schedule 26 is a new charge (approved by FERC in 2006) which MISO plans to initiate as a result of the first phase of their allocation methodology to collect and distribute costs associated with capital investment in transmission infrastructure. This allocation process, known as Reliability and Economic Cost Benefit Allocation (RECB), has been discussed by MISO stakeholders for many months. The first phase addresses cost-sharing for projects included in the MISO Transmission and Expansion Plan (MTEP) needed primarily for reliability, while the second phase will address cost-sharing for economic based projects in future MTEP reports.

Q: How will Schedule 26 be calculated to recoup costs for Transmission Owners who invest in infrastructure?

A: Schedule 26 will be based on the combined effect of all transmission investments in the MISO footprint. Individual Transmission Owners (TOs) will file transmission capital cost information for specific projects which have been approved for cost-allocation via the MTEP in a form known as Attachments FF and GG[20]. Attachment GG is used to develop a fixed carrying charge rate based

[20] See Petitioner's Exhibit No. WSS-1, page 9 of 23, lines 9-23.

on annual revenue requirement calculations for return on rate base, depreciation, incremental O&M expenses and pertinent taxes. Load Serving Entities, which describes all traditional utilities in Indiana, will be assessed fees based on their load ratio share and an 80/20 split between those members within the project's sub region and the MISO footprint. The Company plans to include these charges or credits, which will be billed through Schedule 26, in the MCC.

Q: What reference material describing Schedule 26 is available from MISO?

A: The Schedule 26 tariff sheets, approved on February 4, 2007, are posted on the MISO website.[21] The related Business Practice Manual (No. 005) has not yet been updated.

Q: How does MISO plan to allocate Schedule 26 charges and credits to the Company?

A: According to the Petitioner's Witness Seelye, MISO plans to allocate Schedule 26 charges for any Vectren transmission projects on non-native load only, not to native load. Mr. Seelye explained that MISO plans to allocate Schedule 26 charges for non-Vectren transmission projects to both native and non-native load and distribute credits to the Company based on the *total* revenues which it is eligible to receive for Vectren transmission projects.

Q: How does the Company propose to manage this practice?

A: According to Mr. Seelye, this expected imbalance of expenses and revenues was a catalyst for the Company to develop and propose the second component of the MCRA tracker, the MTC, which is intended to serve as a cost-recovery mechanism for native load. However, Petitioner has included a comparison of all

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[21] See http://www.midwestmarket.org/publish/Document/3b0cc0_10d1878f98a_-7d020a48324a for a full listing of current schedules. Pages 318-323 deal specifically with Schedule 26.

transmission expenses instead of focusing only upon those due to specific capital additions or improvements contained in the MTEP.

Q: How has the Company proposed to calculate MTC charges?

The Company has included MISO operating expenses, MISO revenue expectations and MISO expected return on investment in the MTC component, which it has abbreviated as MISOOE, MISOREV, and MISORET. The OUCC understands that these are based on the Company's records submitted to MISO annually through the mechanism known as Attachment O and FERC Form 1 data. The Company proposes comparing these actual expenses to the amounts included in base rates and passing charges or credits to native load through the MTC.

Q: What concerns does the OUCC have about the proposed cost-recovery for incremental transmission investments?

A: The OUCC is concerned that (1) Schedule 26 has not been implemented yet, (2) the dollars attributed to transmission expansion are overly broad, (3) the level of detail for transmission planning included in bi-annual IRP documents filed with the IURC does not currently ensure prudent options are pursued, (4) cost recovery will impact shareholders and ratepayers of Indiana utilities who are members of MISO and PJM in the future. [22]

The Company has discussed the fact that three catalysts exist for transmission expansion including (1) MISO "mandates", or those included in the MTEP, (2) NERC compliance and (3) new business growth. The OUCC believes catalysts (2) and (3) are part of normal industry operations and existed for years prior to the MISO market; therefore only projects approved for cost recovery through MTEP

[22] The OUCC is engaged in discussions with PJM stakeholders who are in the process of developing a cost-sharing mechanism similar to RECB.

should be considered for purposes of this tracker.

Q: What is the impact on the proposed treatment and other Indiana utilities?

A: We are not sure since the Schedule 26 charge has not yet been implemented. MISO shared a forecast of transmission investments which are expected to rise significantly (in the range of $2.1 to $3.6 billion) during the next five years at the November15, 2006, Advisory Committee meeting. A chart which comprises Attachment JMS-5 indicates expected transmission expenses across the MISO footprint for 2006-2011. The OUCC suggests further clarification and discussion among stakeholders regarding cost recovery and potential rate impacts.

Q: What are the OUCC's recommendations regarding the MCRA?

A: Generally, the OUCC supports the creation of the MCRA based on the MCC components. See Mr. Blakley's testimony for a discussion of the inclusion of specific charges in the MCC, a comparison of Vectren's proposal versus Duke's RTO tracker, suggested time frame and treatment of uninstructed deviation charges in the Fuel Adjustment Clause (FAC).[23] The MTC component should not be implemented at this time. The OUCC recommends the Company develop a means to track expenses for MTEP approved projects and petition this Commission to defer these expenses until a cost recovery mechanism is agreed upon in a separate proceeding. Actual experiences of the impact of Schedule 26 may be helpful in this process as well as providing greater certainty as to actual project scope.

[23] Note: The OUCC suggests the Company rename this component to avoid confusion with the MISO acronym which defines a pricing component known as MCC=Marginal Congestion Component. Perhaps Non-Fuel Component (NFC) will suffice.

EARNINGS TEST

Q: Does Petitioner propose a new methodology for calculation of the FAC Earnings Test?

A: Yes. As explained by Mr. Jerry Benkert on pages 20-25 of his direct testimony, Petitioner advocates the adoption of a Return on Equity (ROE) test in lieu of the statutorily prescribed Net Operating Income (NOI) test.

Q: Has Petitioner proposed a ROE test in any prior proceeding?

A: Yes. A proposed ROE test was included in a settlement between the Petitioner and the OUCC in Cause No. 43046, which primarily involved energy efficiency and rate decoupling. The Petitioner also proposed a ROE test for the calculation of the GCA Earnings Test in its companion gas rate case in Cause No. 43112 currently pending before the Commission.

Q: Did the Commission Approve the ROE test in Cause No. 43046?

A: No. The Commission's order dated December 1, 2006 included a thoughtful discussion of the proposed ROE test but ultimately did not approve it as requested by the settling parties.

Q: Did the Settling Parties accept the modification of the Settlement in IURC Cause No. 43046 that resulted from the Commission's rejection of the ROE test?

A: Yes. The settling parties did not object to the change to the settlement made by the Commission when it rejected the ROE test.

Q: Does the OUCC support the Petitioner's proposal to replace the statutorily prescribed NOI test with the ROE test?

A: Not at this time. As previously stated, the Commission Order was very thoughtful in examining the ROE test proposal. The Commission's order in 43046 was issued very recently and the OUCC is not aware of any change in the law or the facts that would justify a departure from this recent decision by the Commission.

Petitioner's direct testimony was filed prior to the issuance of the Commission Order in Cause No. 43046. Although the Petitioner did not have an opportunity to address the concerns raised by the Commission in this Order, the OUCC anticipates Vectren will respond to the Commission's findings in 43046 in its rebuttal testimony related to the proposed ROE test.

V. RECOMMENDATIONS

Q: What does the OUCC recommend?

A: As discussed above, The OUCC recommends the following:

- Vectren should implement maintenance programs, consistent with good utility practice, but more gradually than Vectren proposes.
- Vectren should provide the Commission and the OUCC with periodic reports on the status of its maintenance programs.
- Service quality benchmarks should be created and audited to ensure that Vectren's maintenance plans are enhancing its system reliability.
- The Commission should modify Vectren's proposal for adding line specialists since the need to do so is not fully supported by Vectren's evidence.
- The Commission should modify Vectren's proposed GCRA and MCRA trackers to exclude environmental costs and the MTC component respectively.
- The Commission should reject Vectren's proposal to replace the NOI test with a ROE test for purposes of the FAC earnings test.
- The Commission should initiate a rate review five (5) years following a rate order in this case to identify the benefits of maintenance and technology improvements.

Q: Does this conclude your testimony?

A: Yes, it does.

Is It Time for a Recloser Checkup?

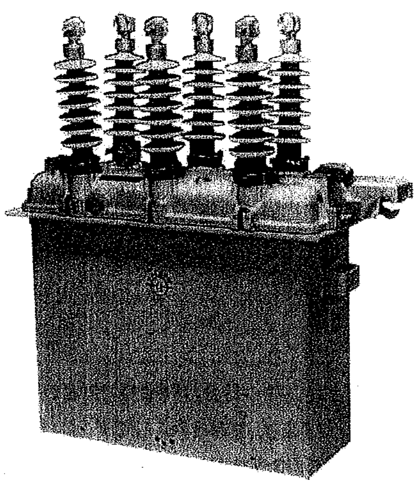
Give Your Recloser a Clean Bill of Health

Regular Maintenance

Would a successful overnight delivery service rely on a vehicle whose oil hasn't been changed in 25,000 miles? The answer is absolutely not. The successful delivery service knows reliability depends on performing routine preventative maintenance on its fleet.

Likewise, keeping your recloser in prime condition is the key to delivering reliable power distribution to your customers. Preventative maintenance is as necessary to the dependable operation of your single-phase and three-phase reclosers as oil changes are to keeping an automobile in good working condition.

Establishing a periodic maintenance program for your recloser inventory ensures that the dielectric properties, physical condition, and the overall performance of each recloser is maintained at a high standard.



Frequency of Recloser Maintenance

Because reclosers are used under widely varying operating and climatic conditions, maintenance intervals are best determined by the user, based on actual operating experience. In the absence of actual operating experience and to assure proper and trouble-free operation, the following guidelines are recommended:

- Oil-interrupting reclosers should be maintained at least every three years.
- Oil-insulated vacuum interrupting reclosers should be maintained at least every six years.
- Air-insulated vacuum interrupting reclosers should be maintained at least every six years.

Reclosers also must be maintained when they have operated the equivalent of a rated duty cycle. The rated duty cycle is the maximum number of fault interruptions a recloser is capable of performing before servicing is required. The duty cycle rating varies for each recloser, and in general terms, vacuum interrupters have the higher duty cycle compared to oil interrupters.

At the completion of a duty cycle, an oil-interrupting recloser's interrupter assemblies, stationary contacts, and movable contacts will be badly eroded and burned. In addition, the condition of the insulating oil will be of poor quality. The insulating oil will be black and dirty and a significant amount of sludge (carbon build up) will have covered the recloser's internal components. Several unwanted by-products, including water, will be present in the oil.

At the end of a vacuum-interrupting recloser's duty cycle, the vacuum interrupter contacts are eroded and worn and the vacuum interrupters should be replaced. Insulating oil will not be degraded since the arc is contained within the vacuum interrupters. The oil should be changed or filtered as it may have reduced dielectric strength. In addition, there may be water present in the oil.

General Periodic Recloser Inspection and Maintenance Checklist

√ Clean and visually inspect the exterior
- Bushings
- Head casting
- Hardware

√ Check for mechanical damage by manually operating the recloser

√ Untank the recloser and clean the mechanism

√ Remove and inspect the bushings

√ Replace gaskets

√ Clean and inspect internal components
- Electrical components
- Closing coil contactor
- Closing coil
- Series trip coil
- Movable and stationary contacts
- Vacuum interrupters

Replace/filter oil

Inspect and replace tank liners

Perform tests
- High Potential withstand test
- Functional tests
- Time Current Curve conformance

Kyle Service Center

Kyle Distribution Switchgear Service is your recloser specialist. The factory offers complete manufacturing and service, including factory production testing and verification, original Cooper Power Systems replacement parts, latest design modifications, and factory-based training and repair classes.

For further information, contact your Cooper Power Systems representative or visit our website at www.cooperpower.com/Services/

Customized Service Contracts

The Kyle Service Center can customize a service contract to meet your needs. Here are a few of the options we offer:

- Performing preventative maintenance
- Maintaining customer maintenance records
- Sending maintenance reminders
- Setting up a maintenance schedule

Authorized Service Shops

Cooper Power Systems has several authorized and certified service centers located throughout the continental United States to provide maintenance, repair, and testing services for Kyle controls and reclosers. Each authorized service shop has complete testing and repair facilities, procedures, and knowledge to provide complete maintenance and servicing of reclosers.

The repair shops are factory-authorized based upon periodic inspections to assure that each repair shop maintains a high level of quality and service for the maintenance, repair, and testing of reclosers.

Visit our Authorized Repair Shops page at www.cooperpower.com/Services/ for a complete listing of service centers. Let our Authorized Repair Shop customize a service contract for you.

The maximum maintenance intervals are three years for oil-interrupting reclosers and six years for oil-insulated and air-insulated vacuum-interrupting reclosers.

Attachment
JMS-2

Vectren Energy Delivery of Indiana - South
I.U.R.C No. E-12
Response to 2nd Informal Data Request
MISO DAY 2 Charge Type Disposition Summary by Statement Order
Revised February 23, 2007

Day 2 Statement Order	Schedule / Charge Type Description	Current Disposition	Rate Case Treatment	Notes
1	Day Ahead Market Administration Amount	Deferred	MCRA	
2	Day Ahead Asset Energy Amount	FAC - MISO Component	FAC	
3	Day Ahead Financial Bilateral Transaction Congestion Amount	FAC - Purchase Power	FAC	
4	Day Ahead Financial Bilateral Transaction Loss Amount	FAC - Purchase Power	FAC	
5	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
6	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
7	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	FAC - Purchase Power	FAC	None since May, 2005
8	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	FAC - Purchase Power	FAC	None since May, 2005
9	Day Ahead Non-Asset Energy Amount	FAC - Purchase Power	FAC	
10	Day Ahead Revenue Sufficiency Guarantee Distribution Amount **(Pre 12/09/05)**	Deferred	Base Rates	May 4, 2006 IURC Order
10	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	FAC - MISO Component	FAC	
11	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	FAC - MISO Component	FAC	
12	Day Ahead Schedule 24 Allocation Amount	Expensed	MCRA	Began June 1, 2006
13	Day Ahead Virtual Energy Amount	FAC - MISO Component	FAC	For Load Only 1 trans 4/22/06
14	Financial Transmission Rights Market Administration Amount	Deferred	MCRA	
15	Financial Transmission Rights Hourly Allocation Amount	FAC - MISO Component	FAC	
16	Financial Transmission Rights Monthly Allocation Amount	FAC - MISO Component	FAC	
17	Financial Transmission Rights Transaction Amount	FAC - MISO Component	FAC	
18	Financial Transmission Rights Yearly Allocation Amount	FAC - MISO Component	FAC	
19	Real Time Market Administration Amount	Deferred	MCRA	
20	Real Time Asset Energy Amount	FAC - MISO Component	FAC	
21	Real Time Financial Bilateral Transaction Congestion Amount	FAC - Purchase Power	FAC	
22	Real Time Financial Bilateral Transaction Loss Amount	FAC - Purchase Power	FAC	
23	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
24	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
25	Real Time Distribution of Losses Amount	FAC - MISO Component	FAC	
26	Real Time Miscellaneous Amount	Deferred	MCRA	
27	Real Time Non-Asset Energy Amount	FAC - Purchase Power	FAC	
28	Real Time Net Inadvertent Distribution Amount	FAC - MISO Component	FAC	
29	Real Time Volatility Make Whole Payment Amount	FAC - MISO Component	FAC	Expected to begin April 1,2007
30	Real Time Revenue Neutrality Uplift Amount	Deferred	MCRA	
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount - **Contestable**	Deferred	Expense or Request Recovery in FAC	May 4, 2006 IURC Order
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount **(Pre 12/09/05)**	Deferred	Base Rates	May 4, 2006 IURC Order
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount **(< Benchmark)**	FAC - MISO Component	FAC	
32	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	FAC - MISO Component	FAC	
33	Real Time Schedule 24 Allocation Amount	Expensed	MCRA	Began June 1, 2006
34	Real Time Schedule 24 Distribution Amount	Expensed	MCRA	Began June 1, 2006
35	Real Time Uninstructed Deviation Penalty Amount	FAC - MISO Component	FAC	Granted recovery in Cause No. 38708-FAC 73
36	Real Time Virtual Energy Amount	FAC - MISO Component	FAC	For Load Only 1 trans 4/22/06

Attachment
JMS-3

Vectren Energy Delivery of Indiana - South
I.U.R.C No. E-12
Response to 2nd Informal Data Request
MISO DAY 2 Charge Type Disposition Summary by Disposition Type
Revised February 23, 2007

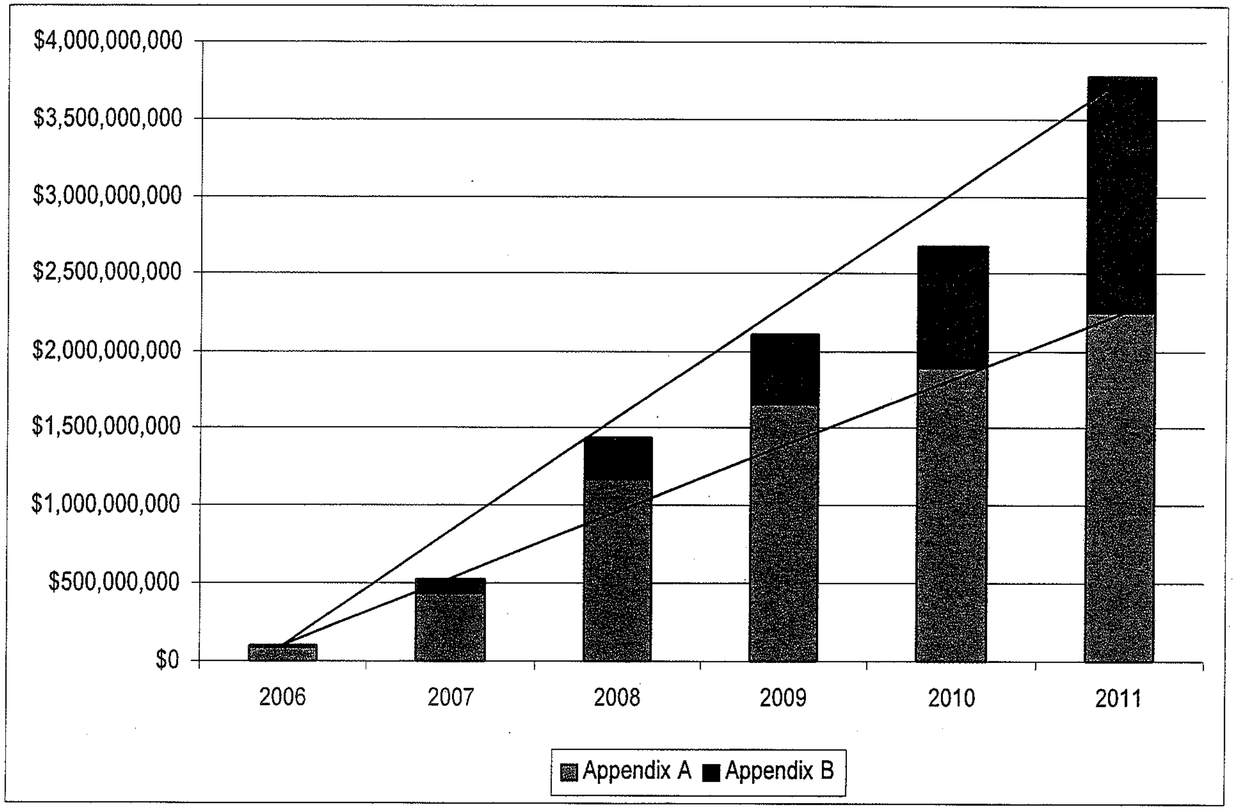
Day 2 Statement Order	Schedule / Charge Type Description	Current Disposition	Rate Case Treatment	Notes
10	Day Ahead Revenue Sufficiency Guarantee Distribution Amount **(Pre 12/09/05)**	Deferred	Base Rates	May 4, 2006 IURC Order
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount **(Pre 12/09/05)**	Deferred	Base Rates	May 4, 2006 IURC Order
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount - **Contestable**	Deferred	Expense or Request Recovery in FAC	May 4, 2006 IURC Order
2	Day Ahead Asset Energy Amount	FAC - MISO Component	FAC	
3	Day Ahead Financial Bilateral Transaction Congestion Amount	FAC - Purchase Power	FAC	
4	Day Ahead Financial Bilateral Transaction Loss Amount	FAC - Purchase Power	FAC	
7	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	FAC - Purchase Power	FAC	None since May, 2005
8	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	FAC - Purchase Power	FAC	None since May, 2005
9	Day Ahead Non-Asset Energy Amount	FAC - Purchase Power	FAC	
10	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	FAC - MISO Component	FAC	
11	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	FAC - MISO Component	FAC	
13	Day Ahead Virtual Energy Amount	FAC - MISO Component	FAC	For Load Only 1 trans 4/22/06
15	Financial Transmission Rights Hourly Allocation Amount	FAC - MISO Component	FAC	
16	Financial Transmission Rights Monthly Allocation Amount	FAC - MISO Component	FAC	
17	Financial Transmission Rights Transaction Amount	FAC - MISO Component	FAC	
18	Financial Transmission Rights Yearly Allocation Amount	FAC - MISO Component	FAC	
20	Real Time Asset Energy Amount	FAC - MISO Component	FAC	
21	Real Time Financial Bilateral Transaction Congestion Amount	FAC - Purchase Power	FAC	
22	Real Time Financial Bilateral Transaction Loss Amount	FAC - Purchase Power	FAC	
25	Real Time Distribution of Losses Amount	FAC - MISO Component	FAC	
27	Real Time Non-Asset Energy Amount	FAC - Purchase Power	FAC	
28	Real Time Net Inadvertent Distribution Amount	FAC - MISO Component	FAC	
29	Real Time Volatility Make Whole Payment Amount	FAC - MISO Component	FAC	Expected to begin April 1,2007
31	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount **(< Benchmark)**	FAC - MISO Component	FAC	
32	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	FAC - MISO Component	FAC	
35	Real Time Uninstructed Deviation Penalty Amount	FAC - MISO Component	FAC	Granted recovery in Cause No. 38708-FAC 73
36	Real Time Virtual Energy Amount	FAC - MISO Component	FAC	For Load Only 1 trans 4/22/06
1	Day Ahead Market Administration Amount	Deferred	MCRA	
12	Day Ahead Schedule 24 Allocation Amount	Expensed	MCRA	Began June 1, 2006
14	Financial Transmission Rights Market Administration Amount	Deferred	MCRA	
19	Real Time Market Administration Amount	Deferred	MCRA	
26	Real Time Miscellaneous Amount	Deferred	MCRA	
30	Real Time Revenue Neutrality Uplift Amount	Deferred	MCRA	
33	Real Time Schedule 24 Allocation Amount	Expensed	MCRA	Began June 1, 2006
34	Real Time Schedule 24 Distribution Amount	Expensed	MCRA	Began June 1, 2006
5	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
6	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
23	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market
24	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	N/A - Purchase Power	N/A	None since start of market

Attachment
JMS-4

Midwest ISO
We manage power.

Steady Investment Through 2011

Cumulative Projected Spending All Projects



OUCC TESTIMONY of WES R. BLAKLEY
Cause No. 43111
VECTREN – ELECTRIC RATE CASE

Q: Please state your name and business address.

A: My name is Wes R. Blakley and my business address is 100 N. Senate Avenue Room N501, Indiana Government Center North, Indianapolis, Indiana 46204-2208.

Q: By who are you employed and in what capacity?

A: I am a Senior Utility Analyst for the Office of Utility Consumer Counselor (OUCC).

Q: Please summarize your educational background and experience as an accountant.

A: I received a Bachelor of Science Degree in Business with a major in Accounting from Eastern Illinois University in 1987. Upon graduation, I worked as a Revenue Accountant and later as a Billing Supervisor for Illinois Consolidated Telephone Company. My primary duties included supervising the audit of the billing system, analyzing and recording revenues and filing related sales and excise tax returns. I continued in that capacity until April 1991, when I accepted a staff accountant position with the OUCC. I have attended the NARUC annual commissioners' conference in Lansing, Michigan. I am a licensed CPA in the State of Indiana.

Q: Have you previously testified before the Indiana Utility Regulatory Commission (IURC)?

A: Yes. I have testified in water, sewer, electric and gas rate case proceedings.

Q: What is the purpose of your testimony in this Cause?

A: The purpose of my testimony is to give an opinion on the request by Petitioner for a Generation Cost and Revenue Adjustment tracker (GCRA) and its MISO Cost and Revenue Adjustment (MCRA) tracker.

Q: What is the GCRA?

A: The GCRA is a mechanism that tracks several elements.

The items proposed to be tracked are:

1. Non-Firm Wholesale (NFW) margins
2. Municipal Wholesale (MW) margins
3. Purchased Power Non-Fuel costs
4. Environmental Chemical costs.
5. Environmental Emission Allowance credits.
6. Direct Load Control (DLC) billing credits
7. Interruptible Sales billing credits.

The expenses listed above for recovery in the GCRA cover the areas of purchased power, environmental cost and demand-side management expenses.

Q: Do you have concerns with multi-expense element tracker?

A: Yes I do. First, the expense elements that are listed are already being tracked in existing trackers by of several utilities including Petitioner. Purchase power trackers exist (*e.g.* Duke Indiana), environmental costs are recovered in environmental cost recovery trackers (ECR's) are common among Indiana electric utilities and costs for direct load control and interruptible sales credits are recovered through DSM and reliability trackers. Finally, there is, of course, the fuel adjustment clause (FAC) tracker. What these trackers have in common is that they all relate to a single expense type (fuel, DSM etc.) and they are created by statute or Commission rule. I believe that combining several single issue trackers into one large multi-expense tracker does not make it easier to understand nor easier to audit. In fact, based upon my experience, I believe it will make things more complex having analysts juggle several different issues on different expenses at once.

Q: Do you have concerns with the actual name of the GCRA?

A: Yes I do. The term "generation cost" can be very broad. There are many generation operation and maintenance (O&M) expenses. The current request includes seven elements, some have netting features, but for the most part, this is a multi-expense recovery tracker. In the future there may be attempts to add other so called "generation" expenses to the tracker. In fact, this request has in it an element that opens the door to this.

Q: What item are you referring to?

A: I'm referring to Petitioner's request to include environmental chemical costs in its GCRA tracker. Petitioner's witness Ulrey states on page 15 line 11 of his testimony:

> Appendix F recovers the operating costs of Vectren South's NOx control investments, including depreciation and chemical costs pursuant to the Commission orders in Cause Nos. 42248 and 42941. Vectren South has rolled these costs into its revenue requirement in this proceeding. Just like the QPCP-CC Adjustment, the QPCP-OE Adjustment will be eliminated at the effective date of new rates.

Mr. Ulrey further testifies, "Vectren South proposes to continue to track environmental chemical costs via its proposed GCRA." Petitioner is actually requesting a continuation of tracking its environmental chemical operating expenses related to its NOx program.

Q: So you are saying that the Phase 1 NOx pollution control equipment is now substantially complete and all costs including investment, depreciation and O&M will now be embedded in current rates as a result of this Cause.

A: Yes that's right, but Petitioner wants to continue to take the environmental chemical costs associated with this program and track into the future.

Q: What is the problem with tracking this single O&M expense into the future?

A: It is unfair and inconsistent to only consider one isolated operation and maintenance expense without considering other expenses that may increase or decrease and/or matching revenues that may increase or decrease. This portion of Petitioner's GCRA request amounts to "cherry picking" a single operating expense. The reality is that there are quite a large number of costs and revenues that arguably could be considered eligible for tracker recovery under the broad definition applications as proposed here. The OUCC is concerned that such tracking may disproportionately address costs which trend upwards without tracking other costs which trend downward or revenues that increase.

Q: **Does Petitioner currently collect operation and maintenance expenses in another tracker associated with recovery of environmental costs?**

Yes it does. Petitioner has recently started construction of its next phase of NOx pollution control equipment for its Multi-Pollutant Plan program (MPP). The Company has recently started to track O&M expenses for the MPP in Cause No. 42861OER-1. These expenses will be tracked until the next general rate case, at which time they will be rolled into base rates.

Q: **What is your recommendation relating it to Petitioner's GCRA tracker request.**

A: The QPCP statutes do not provide a continuation of tracking of investment depreciation or operation and maintenance expenses after the investment and expense has been placed into base rates and adjusted properly pro forma.

Therefore, I recommend that the environmental chemical costs which have been rolled into rates and adjusted pro forma shall be recovered accordingly and shall not be included in any tracking mechanism in this Cause. I also recommend that Petitioner pursue cost recovery of non-firm wholesale margins, municipal wholesale margins, purchase power non-fuel costs, environmental emission allowance credits and interruptible sales billing credits through a reliability tracker, and direct-load control billing credits through a separate DSM tracker.

Q: What is the MCRA?

A: The MCRA contains two components. The MISO Charge Component (MCC) recovers MISO Schedules 10, 16 and 17 and other Day 2 charges, and the MISO Transmission Component (MTC) recovers incremental transmission costs identified in MISO's FERC approved Attachment O formula rate for Vectren. The purpose of the MTC is to provide for recovery of incremental transmission costs above or below the amount to be reflected in base rates in this proceeding.

Q: Petitioner states that the MCRA is "largely modeled after PSI's (Duke Indiana's) Standard Contract Rider No. 68. RTO tracker". Do you agree?

A: Not totally. The MCC portion of the MCRA is similar to Duke's in that it recovers Schedule 10,16 and 17 and other Day 2 charges. Duke does not include Schedules 24 and 26 as the Petitioner has proposed. See Attachment WRB-1 for a comparison of the two trackers. Duke also includes a netting of MISO transmission revenues assigned to it in its RTO tracker. Petitioner does not include this in its MCC portion. The main difference with Petitioner's MCRA compared to Duke's RTO tracker is that the MTC mechanism that recovers incremental transmission costs identified in FERC's Attachment O does not exist in Duke's tracker. OUCC witness Joan Soller describes in her testimony the concerns that the OUCC has for this part of Petitioner's MCRA request.

Q: Did Petitioner initially include Uninstructed Deviation Amount (UD) in its MCRA proposal?

A: Yes, but through negotiations with the OUCC and subsequent Commission order, Petitioner agreed to put all UD amounts through the FAC in Cause 38708-FAC-73 order dated January 31, 2007.

Q: Do you have an opinion on the frequency of tracker filings?

A: Yes I do. Petitioner has requested to file the GCRA and the MCRA on a quarterly basis. These trackers contain many different elements at their inception. This amount of activity filed four times a year in a summary proceeding will be quite burdensome. I believe that for any tracking mechanism(s) created in this Cause, attention should be paid to the frequency and timing of the filings, be it annually, semi annually or quarterly. Other than the FAC, the OUCC contends that any other trackers should not occur any more frequent than semi-annually.

Q: What is your opinion about work-paper templates or schedules for these trackers.

A: The OUCC would like to work collaboratively with the Petitioner to develop templates based on what components the Commission decides to include in the proposed trackers.

Q: Does this conclude your testimony?

A: Yes, it does.

Attachment
WRB-1

Vectren Electric
Cause No. 43111
Comparison of MISO Trackers

	Duke	Vectren
1. Day-Ahead Revenue Sufficiency Guarantee	RTO	FAC thru 5/08
2. Real-Time Revenue Sufficiency Guarantee	RTO	FAC thru 5/08
3. Real-Time Revenue Neutrality Uplift	RTO	MCRA-MCC
4. Real-Time Miscellaneous Amount	RTO	MCRA-MCC
5. Real-Time Uninstructed Deviation Amount	FAC	FAC
6. Schedule 22 thru and out PJM	RTO	MCRA-MCC
7. Schedule 10 Adminstrative	RTO	MCRA-MCC
8. Schedule 16	RTO	MCRA-MCC
9. Schedule 17	RTO	MCRA-MCC
10. Schedule 24	Deducted from RTO	MCRA-MCC
11. Schedule 26	Not requested	MCRA-MCC

TESTIMONY OF J. RANDALL WOOLRDGE
CAUSE NO. 43111
VECTREN – ELECTRIC RATE CASE

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the State of Indiana - Office of Utility Consumer Counsel (OUCC) to provide an opinion as to the overall fair rate of return or cost of capital for Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. ("Vectren South – Electric" or "Company"). I have also been asked to evaluate Vectren South's rate of return testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR VECTREN SOUTH - ELECTRIC IN THIS PROCEEDING.

A. To arrive at an equity cost rate for the Company, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a group of publicly-held electric utility companies. My analysis indicates an equity cost rate in the range of 9.25% for the Company. I have adopted the Company's proposed capital structure ratios and senior capital cost rates. Using these inputs, I am recommending an overall fair rate of return of 6.77% for Vectren South - electric utility. This recommendation is summarized in Exhibit_(JRW-1) and the table below:

Capital Source	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.65%	6.04%	2.33%
Common Equity	47.05%	9.25%	4.35%
Customer Deposits	0.48%	5.39%	0.03%
Cost-free Capital	13.06%	0.00%	0.00%
JDITC	0.76%	7.80%	0.06%
Total	**100.00%**		**6.77%**

As discussed in my testimony, my recommendation is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the *Jobs and Growth Tax Relief Reconciliation Act of 2003* which reduced the tax rates on dividend income and capital gains.

In developing my recommendation, I have reviewed the testimony and recommendations of Vectren South - Electric witnesses Mr. Robert L. Goocher and Mr. Paul R. Moul. I have used Mr. Moul's group of electric utility companies in developing an equity cost rate for Vectren South - Electric. In addition, I have adopted the Company's proposed capital structure and senior capital cost rates. This is quite fair to the Company since I have elected to not include short-term debt in the capital structure in the ratemaking capitalization despite the fact that Vectren Corp., as well as other electric utility companies, consistently use short-term debt as a source of capital. Consequently, the major area of contention in this case is the proposed equity cost rate for Vectren South - Electric.

Equity Cost Rate

Mr. Moul's equity cost rate estimate is 12.00%. My analysis indicates an equity cost rate of 9.25% range for Vectren South – Electric. Mr. Moul has employed Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Risk Premium (RP), and Comparable Earnings (CE) approaches to estimating an equity cost rate for Vectren South - Electric. I have employed the DCF and CAPM methodologies. We have both applied these approaches to the same group of ten electric utility companies.

In terms of the DCF approaches, the major areas of disagreement include the DCF growth rate and Mr. Moul's adjustments for leverage and flotation costs. Mr. Moul's DCF growth rate is excessive because he has not recognized the upwardly biased nature of the forecasted growth rates of Wall Street analysts as well as those of *Value Line*. His adjustments for leverage and flotation costs are unwarranted and simply serve to inflate his DCF equity cost rate. Even with these errors, he has given his DCF results very little weight in estimating an equity cost rate for Vectren South - Electric. I have used both historic and projected growth rate measures, and I included in my analysis the growth in dividends, book value, and earnings per share. In addition, I have not made Mr. Moul's unwarranted flotation and leverage adjustments.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Mr. Moul's risk-free interest rate, betas, and equity risk premium are all excessive and do not reflect current market fundamentals. Mr. Moul's risk-free interest rate of 5.50% is more than 50 basis points above the current yield on long-term Treasury bonds. He makes an unwarranted leverage adjustment, which is similar in concept to his adjustment to his DCF equity cost rate, to the betas for the electric utility companies. The equity risk premium in Mr. Moul's CAPM is the average of a historic equity risk premium of 6.50% and a projected equity risk premium of 6.04%. As I highlight in my testimony, there are three procedures for estimating an equity risk premium – historic returns, surveys, and expected return models. I provide evidence that risk premiums based on historic returns series, as well as those using analysts' projections, are upwardly biased measures of expected equity risk premiums. I use an equity risk premium of 4.15% which (1) uses all three approaches to estimating an equity premium and (2) employs the results of many studies of the equity risk premium. As I note, my equity risk premium is consistent with the equity risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) that result from surveys of financial forecasters and corporate CFOs.

Mr. Moul and I also disagree on the need for a size premium and flotation cost adjustment to the CAPM. The size premium is based on historical stock returns and, as discussed in my testimony, there are a number of errors in using historical market returns to compute risk premiums. In addition, I argue that any equity cost rate adjustment based on the relative size of a public utility is inappropriate. One study noted in my testimony tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. The primary reason that a size premium is not required for utilities is that utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an on-going basis by both the state and federal governments.

Finally, Mr. Moul's RP and CE approaches are subject to a number of errors and therefore do not provide reliable estimates of the Company's cost of equity capital.

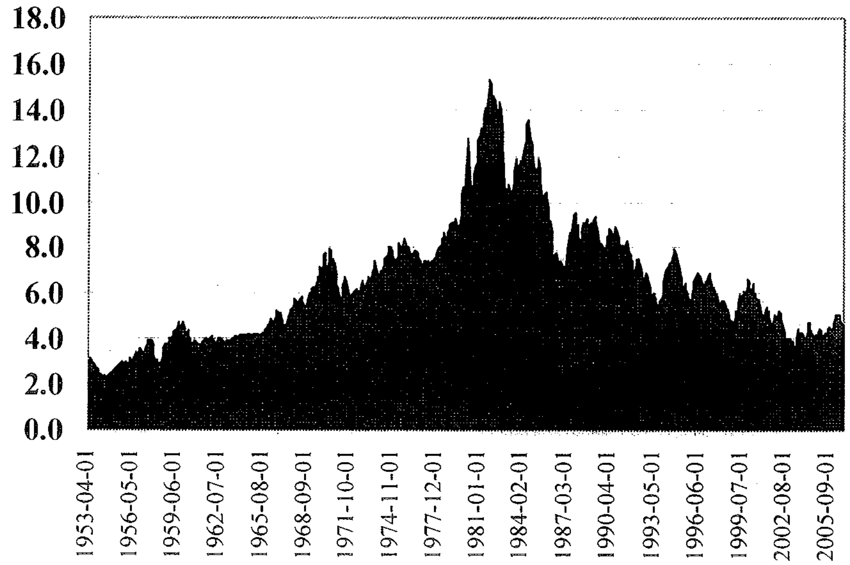
II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of interest rates in the US economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year 2000, the 10-year Treasury yield had not consistently been in the 4-5 percent range over an extended period of time since the 1960s.

Yields on Ten-Year Treasury Bonds

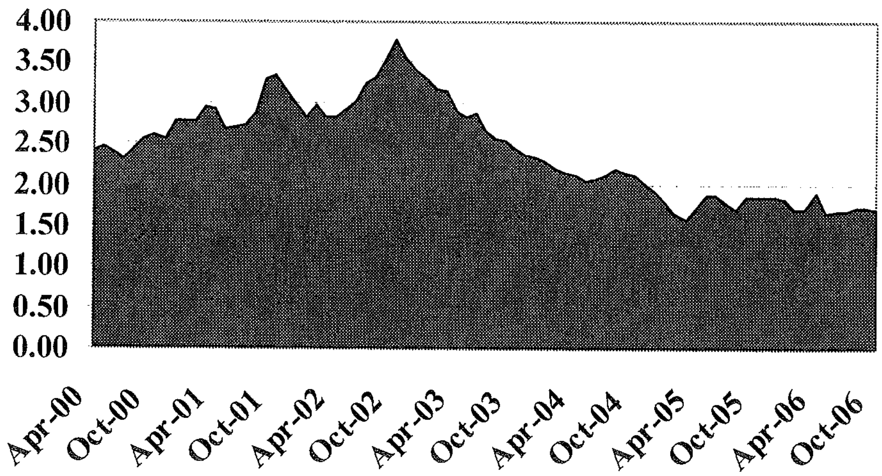
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. Risk premiums for bonds are the yield differentials between different bond classes as rated by agencies such as Moody's, and Standard and Poor's. The graph below provides the yield differential between Baa-rated corporate bonds and 10-year Treasuries. This yield differential peaked at 350 basis points (BPs) in 2002 and has declined significantly since that time. This is an indication that the market price of risk has declined and therefore the risk premium has declined in recent years.

Corporate Bond Yield Spreads
Baa-Rated Corporate Bond Yield Minus Ten-Year Treasury Bond Yield



Source: http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html

The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks* *for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Even Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums have declined during the past decade is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the

---

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p. 15.

> observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades. In addition, the 2003 tax law further lowered capital cost rates for companies.

Q. HOW DID THE *JOBS AND GROWTH TAX RELIEF RECONCILIATION ACT OF 2003* REDUCE THE COST OF CAPITAL FOR COMPANIES?

A. On May 28, 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003*. The primary purpose of this legislation was to reduce taxes to enhance economic growth. A primary component of the new tax law was a significant reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a higher cost of raising capital

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

for corporations. The tax legislation reduced the effect of double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent.

Overall, the 2003 tax law reduced the pre-tax return requirements of investors, thereby reducing corporations' cost of equity capital. This is because the reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The 2003 tax law also reduced the tax rate on long-term capital gains from 20% to 15%. The magnitude of the reduction in corporate equity cost rates is debatable, but my assessment indicates that it could be as large as 100 basis points (See Exhibit_JRW-2).

III. COMPARISON GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR VECTREN SOUTH - ELECTRIC.

A. To develop a fair rate of return recommendation for Vectren South - Electric, I have evaluated the return requirements of investors on the common stock of a group of publicly-held electric utility companies.

Q. PLEASE DESCRIBE YOUR GROUP OF ELECTRIC UTILITY COMPANIES.

A. I am using the group of ten electric utility companies employed by Vectren South - Electric Witness Paul R. Moul. These companies include Alliant Energy, Ameren, DTE Energy, Duke Energy, FirstEnergy, MGE Energy, NiSource, Vectren, Wisconsin Energy, and Xcel Energy.

Summary financial statistics for the group are provided on page 1 of Exhibit_JRW-3. The group has average revenues and net plant of $7,131.3M and $11,940.8M, respectively. The group has an average common equity ratio of 47.2% and a current average earned return on common equity of 9.9%.

IV. <u>CAPITAL STRUCTURE RATIOS AND DEBT COST RATES</u>

Q. PLEASE DISCUSS THE RECOMMENDED AND ACTUAL CAPITAL STRUCTURE OF THE COMPANY (I.E. VECTREN SOUTH - ELECTRIC).

A. The Company's recommended capital structure ratios are provided in Panel A of page 1 of Exhibit_JRW-4. This capitalization includes no short-term debt and has a common equity ratio of 54.90%. In Panels B and C of Exhibit_(JRW-4), I show the average capital structure ratios of the parent company (Vectren Corp.) and the proxy group of electric utility companies for the past four quarters (ending 9/30/2006). Both Vectren Corp. as well as the companies in the proxy group consistently use short-term debt as a source of capital. The average amount of short-term debt in the quarterly capitalization of Vectren Corp. and the electric utility group is 9.81% and 12.39%, respectively. In addition, the average quarterly common equity ratio, when short-term debt is included as a source of capital, is 43.44% for Vectren Corp. and 45.39% for the proxy group.

Q. WHAT CAPITAL STRUCTURE ARE YOU USING IN ESTABLISHING AN OVERALL RATE OF RETURN FOR THE COMPANY?

A. I am adopting the Company's proposed_capital structure which is developed by Mr. Goocher in Petitioner's Exhibit No. RLG-2. This capitalization includes investor provided capital (85.7% of total capital with ratios of 45.10% long-term debt and 54.9% common equity), customer deposits, cost-free capital (deferred income taxes, customer advances for construction, and SFAS 106), and the Job Development Investment Tax Credit (JDITC).

Q. DO YOU BELIEVE THE PROPOSED CAPITAL STRUCTURE IS "FAIR" TO THE COMPANY FOR RATEMAKING PURPOSES?

A. Yes. This is a very fair ratemaking capital structure for Vectren South – Electric because Vectren Corp. as well as the proxy group of electric utilities consistently use short-term debt as a source of investor provided capital, but none has been included for ratemaking purposes.

Q. ARE YOU ALSO ADOPTING THE COMPANY'S SENIOR CAPITAL COST RATES?

A. Yes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. My recommended capital structure and senior capital cost rates are summarized in Panel D of Exhibit_(JRW-4).

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however, and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices which are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility, i.e., provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

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[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm which earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm which earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS?

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

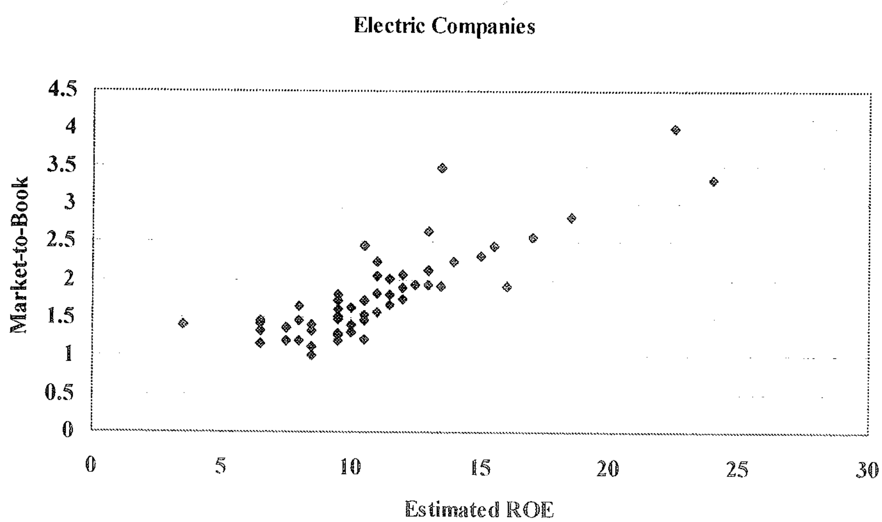
Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three

[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

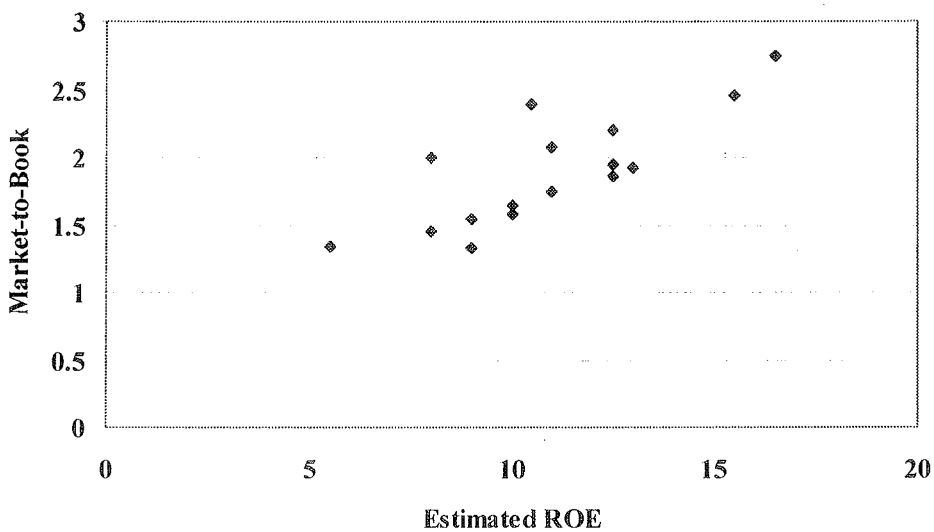
industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics Companies, Gas Distribution Companies, and Water Utilities



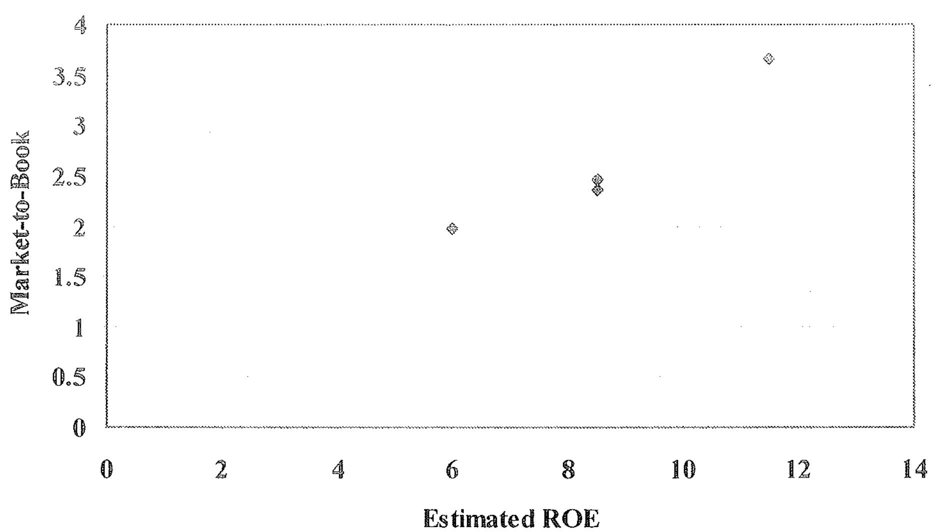
R-Square = .70
N=58

Gas Companies



R-Square = .64
N=16

Water Companies



R-Square = .93
N=4

The average R-squares for the electric, gas, and water companies are 0.70, 0.64, and 0.93. This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.[5]

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit_JRW-5 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year, 'A' rated public utility bonds. These yields peaked in the 1990s at 10%, and have generally declined since that time. They hovered in the 4.5 to 5.0 percent range between 2003 and 2005, and have since increased to 5.75%. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 7.2%. Since that time they have declined and were below 4.0% as of 2005.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit_JRW-5. Over the past decade, earned returns on common equity have consistently been in the 10.0-13.0 percent range. The high point was 13.45% in 2001, and they have decreased since that time. As of 2005, the average was 11.75%. Over the past decade, market-to-book ratios for this group have increased gradually, but with several ups and downs. The market-to-book average was 1.75 as of 2001, declined to 1.45 in 2003, and increased to 1.95 as of 2005.

---

[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

The indicators in Exhibit_JRW-5, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade. Specifically for the equity cost rate, the increase in the market-to-book ratios, coupled with a slightly lower average return on equity, suggests a decline in the overall equity cost rate.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF ELECTRIC UTILITY COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Some investors may perceive potential environmental expenditures associated with clean air compliance as adding an additional element of risk unique to electric utilities. Economic theory would suggest that such perceptions have been captured in the market data I have utilized. Furthermore, investors would also be expected to consider that Indiana permits dollar-for-dollar tracking and timely recovery between rate cases of both capital investment and O&M expenses associated with clean air compliance, which likely serves to mitigate any perceived additional "clean air" risk.

Exhibit_JRW-6 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk that need be of concern for investors. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University.[6] The study shows that the investment risk of public utilities is relatively low. The average beta for electric utility companies of 0.93 is well below the Value Line average of 1.14. As such, the cost of equity for the electric utility industry is below the average of all industries in the U.S.

[6] They may be found on the Internet at http:// www.stern.nyu.edu/~adamodar.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. <u>Discounted Cash Flow Analysis</u>

Q. BRIEFLY DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the discounted cash flow model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock.

Therefore this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model.[7]

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly

[7] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

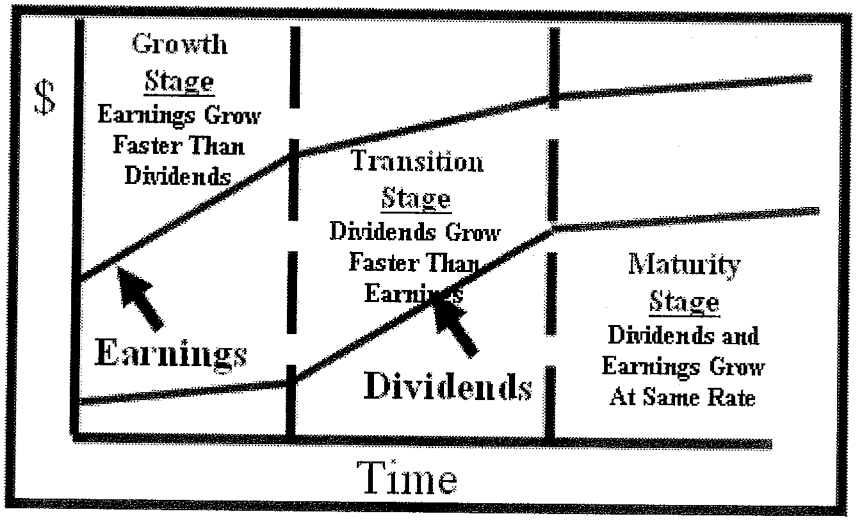
profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Three-Stage DCF Model



Q. **HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?**

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. Therefore, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT_JRW-7.

A. My DCF analysis is provided in Exhibit_JRW-7. The DCF summary is on page 1 of this Exhibit and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR YOUR GROUP OF ELECTRIC UTILITY COMPANIES?

A. The dividend yields on the common stock for the companies in the group are provided on page 2 of Exhibit_JRW-7 for the six-month period ending February, 2007. Over this period, the average monthly dividend yields for the group of electric utility companies was 3.9%. As of February, 2007, the mean dividend yield for the group was 3.9%. For the DCF dividend yields for the group, I use the average of the six month and February, 2007 dividend yields. Hence, I am employing a DCF dividend yield of 3.90%.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by

4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, which pays dividends on a quarterly basis.[8]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

The appropriate adjustment to the dividend yield is further complicated in the regulatory process when the overall cost of capital is applied to a projected rate base. The net effect of this application is an overstatement of the equity cost rate estimate derived from the DCF model. In the context of the constant-growth DCF model, both the adjusted dividend yield and the growth component are overstated. The overstatement results from applying an equity cost rate computed using current market data to a future or test-year-end rate base which includes growth associated with the retention of earnings during the year. In other words, an equity cost rate times a future, yet to be achieved rate base, results in an inflated dividend yield and growth rate.

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[8] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by one-half (1/2) the expected growth so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE GROUP OF ELECTRIC UTILITY COMPANIES?

A. I have analyzed a number of measures of growth for the electric utility companies. I have reviewed *Value Line's* historical and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Zacks, Reuters, and First Call. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the averages of these forecasts on the Internet. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUP AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY.*

A. Historic growth rates for the companies in the group, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit_JRW-7. Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis. The historical growth measures in EPS, DPS, and BVPS for the group, as measured by the means and medians, range from -3.3% to 5.0%, with an average of 1.0%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE GROUP OF ELECTRIC UTILITY COMPANIES.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the group are shown on page 4 of Exhibit_JRW-7. As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the group, the central tendency measures range from 3.8% to 5.8%, with an average of 4.6%.

Also provided on page 4 of Exhibit_JRW-7 is prospective internal growth for the group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. The average prospective internal growth rate for the group is 4.0%.

Q. PLEASE ASSESS GROWTH FOR THE GROUP AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR GROWTH IN EPS.

A. Zacks, First Call, and Reuters collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for companies. These forecasts are provided for the companies in the group of electric utility companies on page 5 of Exhibit_JRW-7. The average of the analysts' projected EPS growth rates for the group is 5.4%.[9]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE ELECTRIC UTILITY GROUP.

A. The table below shows the summary DCF growth rate indicators for the group of electric utility companies. For the group, the average of *Value Line*'s historical mean and median growth rate measures in EPS, DPS, and BVPS is 1.0%. *Value Line*'s average projected growth rate for EPS, DPS, and BVPS is 4.6%. The average internal growth rate is 4.0%, and the average projected EPS growth rate for companies in the group is 5.4%. Given these results, and giving primary weight to the projected growth rate figures, an expected growth rate of 5.25 percent is reasonable for the group.

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[9] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

DCF Growth Rate Indicators

Growth Rate Indicator	Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	1.0%
Projected *Value Line* Growth in EPS, DPS, and BVPS	4.6%
Internal Growth ROE * Retention rate	4.0%
Projected EPS Growth from First Call, Reuters, and Zacks	5.4%

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE GROUP?

A. My DCF-derived equity cost rate for the group is:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

DCF Equity Cost Rate (k) =	Dividend Yield	½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Gas Group	3.9 %	1.02625	5.25%	9.25%

These results are summarized on page 1 of Exhibit_JRW-7.

C. **Capital Asset Pricing Model Results**

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL (CAPM).

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk; and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + \beta_i * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(β_i) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (β_i), and the expected equity or market risk premium, $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. β_i, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium, $[E(R_m) - (R_f)]$. I will discuss each of these inputs, with most of the discussion focusing on the expected equity risk premium.

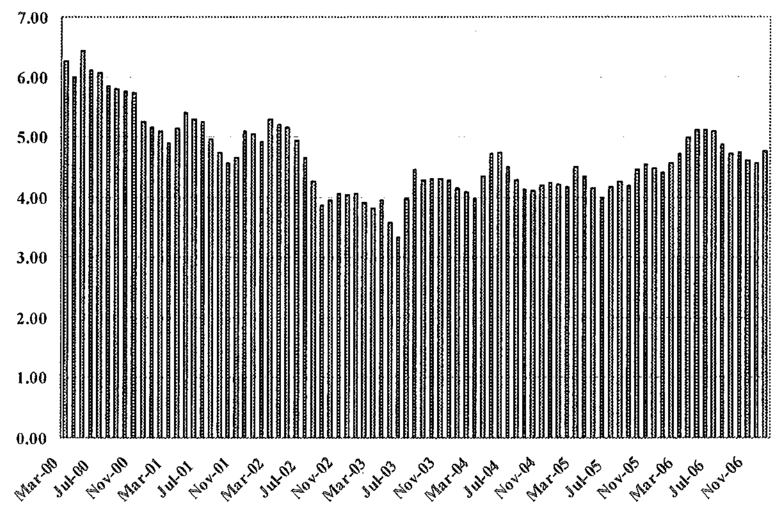
Q. PLEASE DISCUSS EXHIBIT_JRW-8.

A. Exhibit_JRW-8 provides the summary results for my CAPM study. Page 1 shows the results, and the pages following it, contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term Treasury bonds, in turn, has been considered to be the yield on Treasury bonds with 30-year maturities. However, when the Treasury's issuance of 30-year bonds was interrupted for a period of time in recent years, the yield on 10-year Treasury bonds replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. The 10-year Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range over the past three years until advancing to 5.0% in early 2006 in response to a strong economy and increases in energy, commodity, and consumer prices. Beginning in the fourth quarter of 2006, however, long-term interest rates have retreated to below 5.0 percent as commodity and energy prices have declined and inflationary pressures have subsided.

Ten-Year U.S. Treasury Yields
January 2000-January 2007



Source: http://www.federalreserve.gov/releases/h15/current/h15.pdf

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. With the growing budget deficit, the U.S. Treasury has decided to again begin issuing a 30-year bond. As such, the market may again begin to focus on its yield as the benchmark for long-term capital costs in the U.S. In recent months, the yields on the 10- and 30- year Treasuries have increased and have been in the 4.75%-5.25% range. As of February 9, 2007, as shown in the table below, the rates on 10- and 30- Treasuries were 4.78% and 4.87%, respectively. Given this recent range and recent movement, I will use 5.0% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
February 9, 2007

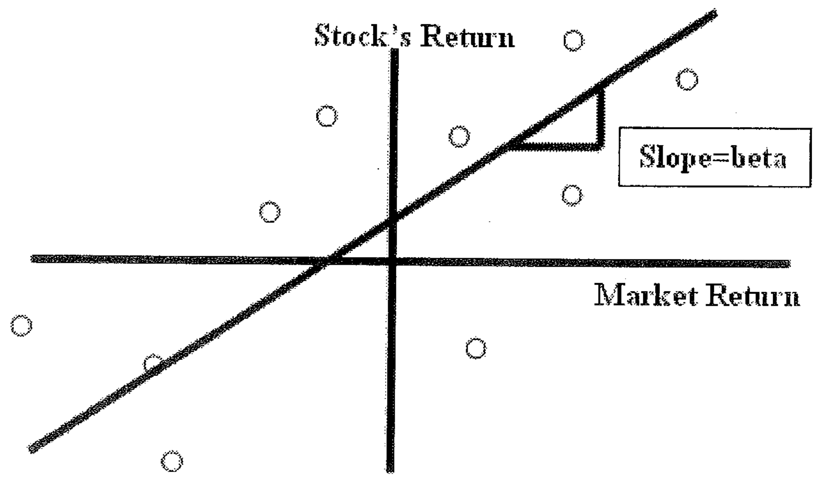
NOTES/BONDS	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
2-YEAR	4.875	01/31/2009	99-29¾ / 4.91
3-YEAR	4.750	02/15/2010	99-25+ / 4.82
5-YEAR	4.750	01/31/2012	99-27+ / 4.78
10-YEAR	4.625	02/15/2017	98-24½ / 4.78
30-YEAR	4.750	02/15/2037	98-06 / 4.87

Source: www.bloomberg.com

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:

Calculation of Beta



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the group of electric utility companies, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit_JRW-8, the average beta for the group is 0.88.

Q. PLEASE DISCUSS THE OPPOSING VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium—$[E(R_m) - R_f]$: is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term Treasury bonds.

However, this can be a problem because (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse, and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[10] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data

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[10] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[11]

Q. PLEASE BRIEFLY SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds; and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data. Fama and French (2002), two of the most preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[12] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are

[11] Rahnish Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

[12] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%.

Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the [(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[13] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by (1) computing the discount rate that equates market values with the present value of expected future cash flows, and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that

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[13] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).

over this period the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock returns that have exceeded investors' expectations and therefore ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. **PLEASE PROVIDE A SUMMARY OF THE EX ANTE EQUITY RISK PREMIUM STUDIES.**

A. Richard Derrig and Elisha Orr (2003) completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[14] These authors reviewed the various approaches to estimating the equity risk premium, and the overall results. Page 3 of Exhibit_JRW-8 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr. In developing page 3 of Exhibit_JRW-8, I have (1) updated the results of the studies that have been updated by the various authors, (2) included the results of several additional studies and

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[14] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, August 28, 2003.

surveys, and (3) included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed which is presented below.

On page 3, the risk premium studies listed under the 'Social Security' and 'Puzzle Research' sections are primarily ex ante expected equity risk premium studies (as discussed above). Most of these studies are performed by leading academic scholars in finance and economics. Also provided are the results of studies by Ibbotson and Chen and myself which use the Building Blocks approach.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EX ANTE EXPECTED EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

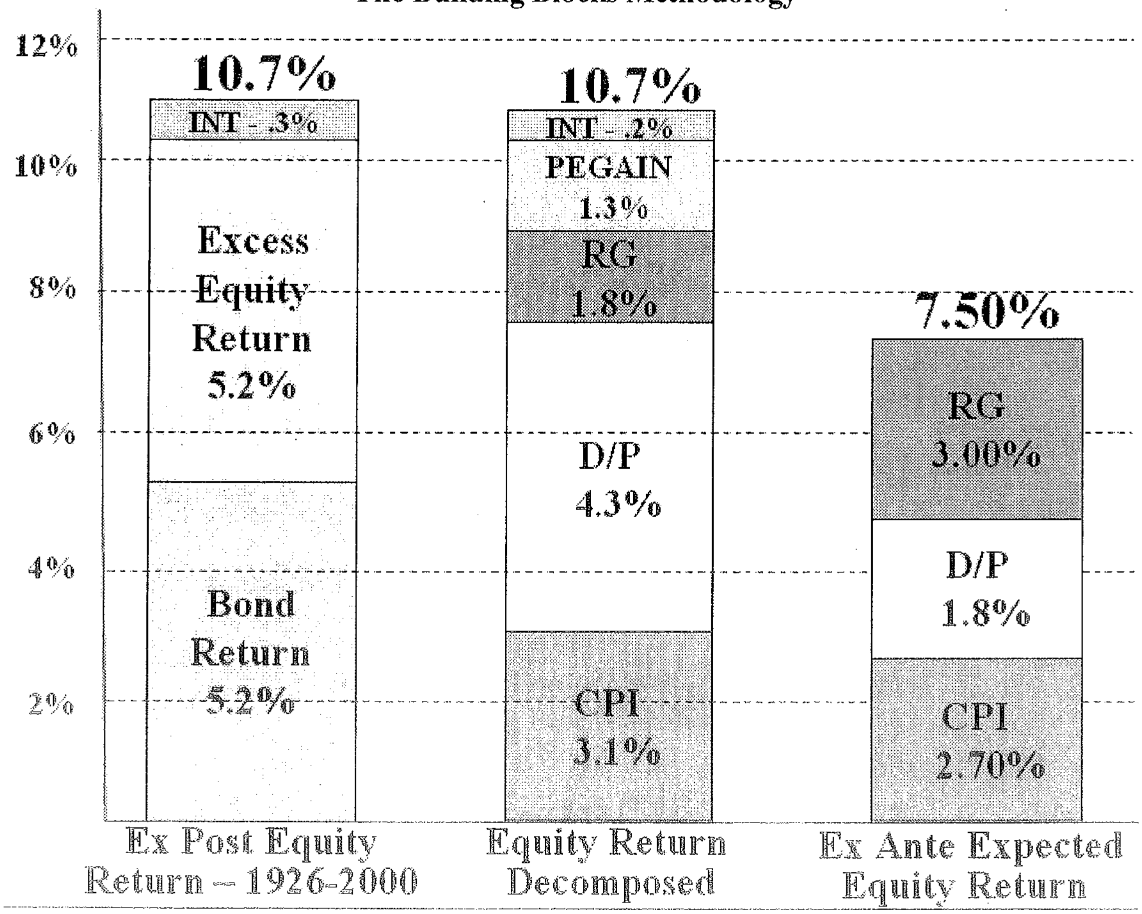
A. Ibbotson and Chen (2002) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[15] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and P/E ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation (CPI), dividend yield (D/P), real

[15] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

earnings growth (RG), repricing gains (PEGAIN) and return interaction/reinvestment (INT).[16] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

[16] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

Decomposing Equity Market Returns
The Building Blocks Methodology



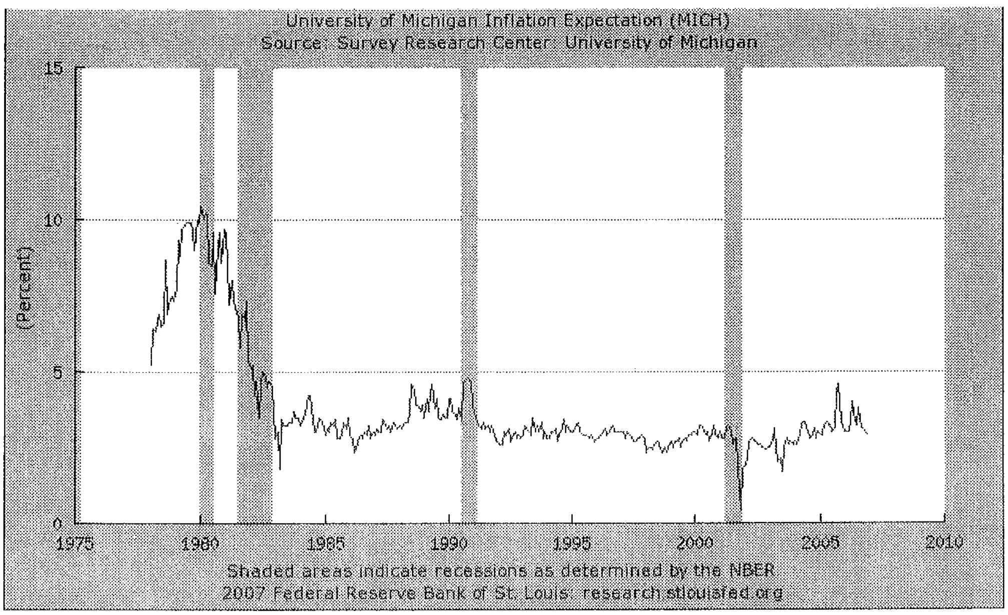
Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year.

This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year inflation rate was 3.0%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[17] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of GDP growth, inflation, and market returns. In the first quarter, 2007 survey,

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[17]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 13, 2007. The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

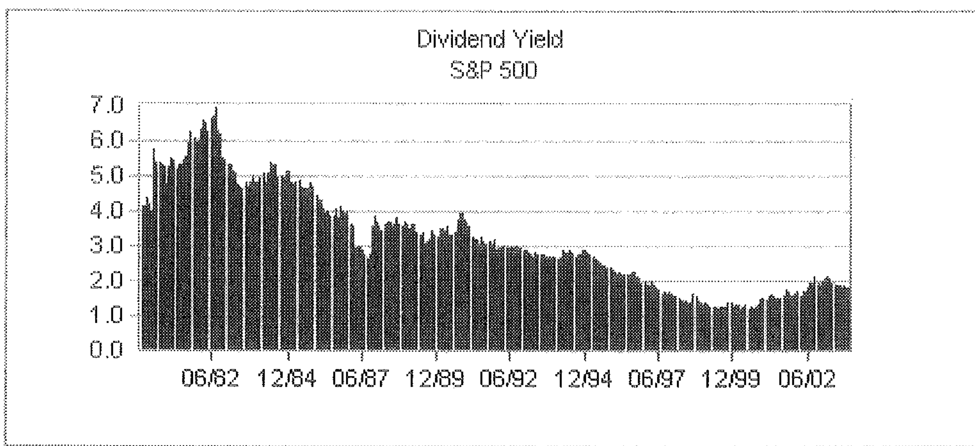
published on February 13, 2007, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.35% (see page 4 of Exhibit_JRW-8).

Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (3.0% and 2.35%), or 2.7%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its average of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 1.8% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield

(Data Source: http://www.barra.com/Research/fund_charts.asp)



RG – To measure expected real growth in earnings, I use (1) the historical real earnings growth rate for the S&P 500, and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2005 period, nominal growth in EPS for the

S&P 500 was 7.11%. On page 5 of Exhibit_JRW-8, real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2006 period for the S&P 500 is 3.0 %.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of US GDP.[18] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 3.0% (see page 4 of Exhibit_JRW-8).

Given these results, I will use the average of the historical S&P EPS real growth and the projected real GDP growth (as reported by the Philadelphia Federal Reserve Survey) -- 3.0% and 3.0% -- or 3.0%, for real earnings growth.

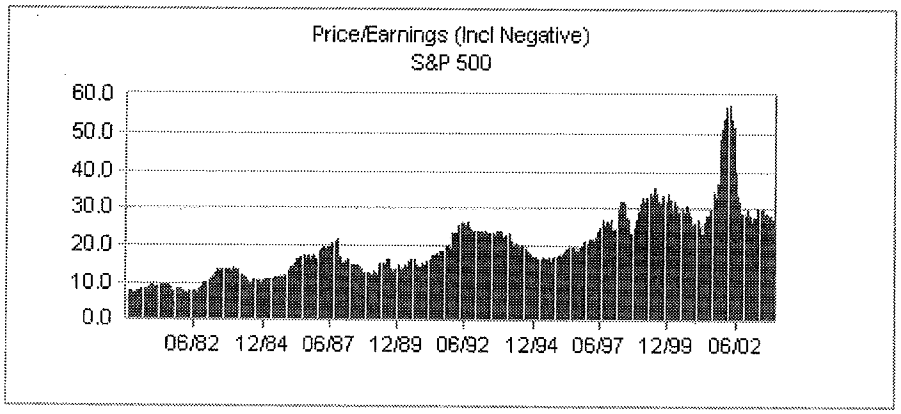
PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10) over two decades ago are also quite notable. As of February, 2007 the P/E for

[18]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

the S&P 500, using the trailing 12 months EPS, is 21.0 according to www.investor.reuters.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is 15 – thus the current P/E exceeds this figure. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rates, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

S&P 500 P/E Ratios
(Data Source: http://www.barra.com/Research/fund_charts.asp)



Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 43 of my testimony. As shown on page 44, my expected market return is 7.50% which is composed of 3.00% expected inflation, 1.80% dividend yield, and 3.00% real earnings growth rate.

Expected Inflation	Dividend Yield	Real Earnings Growth Rate	Expected Market Return
2.70%	1.80%	3.00%	7.50%

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 7.5% IS REASONABLE?

A. As discussed above in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 1.8%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 7.5% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter, 2007 survey, published on February 13, 2007, the median long-term expected return on the S&P 500 was 7.50% (see page 4 of Exhibit_JRW-8). This is consistent with my expected market return of 7.50%.

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct an annual survey of corporate CFOs. The survey is a joint project of Duke University and *CFO*

Magazine. In the 2006 survey, the average expected return on the S&P 500 over the next ten years is 8.40%.[19]

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown in the February 9, U. S. Treasury Yield Chart above, the current 30-year treasury yield is 4.87%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.50% - 4.87% = 2.63%

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit_JRW-8 provides a summary of the results of a variety of the equity risk premium studies. These include the results of (1) the study of historical risk premiums as provided by Ibbotson, (2) ex ante equity risk premium studies (studies commissioned by the Social Security Administration as well as those labeled 'Puzzle Research'), (3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics, (4) Building Block approaches to the equity risk premium, and (5) other miscellaneous studies. The overall average equity risk premium of these studies is 4.15%, which I will use as the equity risk premium in my CAPM study.

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[19] The survey results are available at www.cfosurvey.org.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[20] His study showed that the market or equity risk premium had declined to the 2.0 to 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 to 3.0 percent range above the interest rate on U.S. Treasury Bonds.[21]

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[20] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

[21] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. In the previously-referenced 2006 CFO survey conducted by John Graham and Campbell Harvey, the average ex ante 10-year equity risk premium was 3.80%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously-referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit_JRW-8, the median long-term expected stock and bond returns were 7.50% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.50%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. They recently published a study entitled "The Real Cost of Equity" in which they developed an ex ante equity risk premium for the US. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[22]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the group of electric utility companies are provided below:

$$K = (R_f) + \beta i * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Utility Group	5.00%	0.88	4.15%	8. 7%

D. <u>Equity Cost Rate Summary</u>

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the group of electric utility companies are indicated below:

	DCF	CAPM
Electric Utility Group	9.25%	8.7%

[22] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR VECTREN SOUTH - ELECTRIC?

A. I conclude that the equity cost rate for the group of electric utility companies is in the 8.7-9.25% percent range. Given that I give primary weight to the DCF model, I will use 9.25% for Vectren South- Electric. This appears especially fair in light of my CAPM results.

Q. ISN'T THIS RATE OF RETURN LOW BY HISTORICAL STANDARDS?

A. Yes it is, and appropriately so. My rate of return is low by historical standards for three reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. Second, the 2003 tax law, which reduces the tax rates on dividend income and capital gains, lowers the pre-tax return required by investors. And third, as discussed below, the equity or market risk premium has declined.

Q. FINALLY, PLEASE DISCUSS YOUR RATE OF RETURN IN LIGHT OF RECENT YIELDS ON 'A' RATED PUBLIC UTILITY BONDS.

A. In recent months the yields on long-term public utility bonds have been in the 6.00 percent range. My rate of return may appear to be too low given these yields. However, as previously noted, my recommendation must be viewed in the context of the significant decline in the market or equity risk premium. As a result, the return premium that equity investors require over bond yields is much lower today. This decline was previously reviewed in my discussion of capital costs in today's markets.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my 9.25% equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the companies in the group of electric utility companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE GROUP OF ELECTRIC UTILITY COMPANIES INDICATE ABOUT THE REASONABLENESS OF YOUR 9.25% RECOMMENDATION?

A. Exhibit_JRW-3 provides financial performance and market valuation statistics for the group of electric utility companies. The average current return on equity and market-to-book ratios for the group are summarized below:

	Current ROE	Market-to-Book Ratio
Electric Utility Group	9.9 %	174

Source: Exhibit_JRW-3.

These results indicate that, on average, these companies are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate of 9.25% is reasonable and fully consistent with the financial performance and market valuation of the group of electric utility companies.

VI. CRITIQUE OF VECTREN SOUTH - ELECTRIC'S RATE OF RETURN TESTIMONY

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The Company's proposed rate of return is too high primarily due to an overstated equity cost rate. Mr. Goocher's recommended capital structure contains a relatively high equity ratio since he has not included short-term debt as a source of investor provided capital. However, I am employing this capital structure, which is very fair to the Company.

Q. PLEASE REVIEW MR. MOUL'S EQUITY COST RATE APPROACHES.

A. Mr. Moul uses his proxy group of ten electric utility companies and employs a DCF approach, a Risk Premium (RP) analysis, a CAPM, and a Comparable Earnings (CE) approach.

Q. PLEASE SUMMARIZE MR. MOUL'S EQUITY COST RATE RESULTS.

A. Mr. Moul's equity cost rate estimates for Vectren South – electric are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company to be 12.00%.

Summary of Equity Cost Rate Approaches and Results

Approach	Equity Cost Rate Estimate
DCF	10.58%
Risk Premium	11.71%
CAPM	12.62%
Comparable Earnings	15.25%

Q. PLEASE DISCUSS THE ISSUES WITH MR. MOUL'S RECOMMENDED EQUITY COST RATE.

A. Mr. Moul's proposed return on common equity is too high primarily due to (1) an upwardly-biased expected growth rate in his DCF analysis; (2) an incorrect leverage adjustment for the difference between market values and book values, (3) adjustments to account for the size of the Company as well as for flotation costs, (4) the use of a forecasted interest rates (in his RP and CAPM approaches) that are above current long-term market yields, (5) excessive risk premium estimates in his RP and CAPM approaches, and (6) a flawed Comparable Earnings (CE) approach.

Q. INITIALLY, PLEASE ADDRESS MR. MOUL'S ADJUSTMENT FOR THE SIZE OF THE COMPANY.

A. Mr. Moul adjusts his equity cost rate results (adding 1.02%) to account for the size of the Company. He supports his size premium on the basis of a historical return analysis performed by Ibbotson Associates. As discussed later in my testimony, there are numerous errors in using historical market returns to compute risk premiums. These errors provide inflated estimates of expected risk premiums. Among the errors are the well-known survivorship bias (only successful companies survive – poor companies do not survive) and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). Again, these biases are discussed at more length later in my testimony. The net result is that Ibbotson's size premiums are poor measures for any risk adjustment to account for the size of the Company. This observation is further supported by a review of the Ibbotson study. The Ibbotson study used for the explicit size premium is based on the stock returns for companies in the 10^{th} size decile. A review of Tables 7-5 and 7-7 in the Ibbotson document indicates that these companies have betas that are larger than the betas of electric utility companies. Hence, these size premiums are not associated with the electric utility industry

Finally, and most significantly, Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[23] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an ongoing basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common financial transactions such as the sale of securities. Furthermore, unlike their industrial counterparts, accounting standards and reporting are fairly standardized

[23] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of the Midwest Finance Association*, 1993, PP. 95-101.

for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclosure, utilities are much different than industrials, which could account for the lack of a size premium.

Q. PLEASE ALSO INITIALLY CRITIQUE MR. MOUL'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Moul adjusts his proposed DCF, CAPM, and RP equity cost rates for flotation costs. To identify these costs, Mr. Moul was asked in OUCC-7-233 to provide all financial details regarding test-year equity offerings. However, Mr. Moul provided no specific details of any equity offerings. Therefore, since no specific flotation or equity issuance costs have been identified, there is no reason to provide the Company with additional revenues through a flotation cost adjustment to the allowed rate of return. A flotation cost adjustment in this case would simply provide additional revenues for an expense that (1) the Company has not incurred in the recent past, or (2) the Company has not provided any specific details of in the foreseeable future.

Q. PLEASE SUMMARIZE MR. MOUL'S DCF ESTIMATES.

A. On pages 14-28 of his testimony, in Appendix D, and in Schedules 5-8, Mr. Moul develops an equity cost rate by applying a DCF model to his electric utility proxy group. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. He adjusts this figure for (1) a leverage adjustment to reflect the difference between the market value and book value capital structures of the companies in the electric utility company group, and (2) a flotation cost adjustment. Mr. Moul's DCF results are summarized below.

DCF Equity Cost Rate
Gas Company Proxy Group

	Traditional
Dividend Yield	4.32%
Growth	5.50%
DCF Result	9.82%
Leverage Adjustment	0.55%
Leverage-Adjusted DCF Result	10.37%
Flotation Adjustment	0.21%
DCF Equity Cost Rate	**10.58%**

Q. PLEASE EXPRESS YOUR CONCERNS WITH MR. MOUL'S DCF STUDY.

A. Beyond my previously-discussed concerns on the flotation cost adjustment, I have several issues with Mr. Moul's DCF equity cost rate. These are the dividend adjustment, the DCF growth rate of 5.50%, and the leverage adjustment.

Q. PLEASE EVALUATE THE DIVIDEND YIELD IN MR. MOUL'S DCF STUDY.

A. In Appendix D, Mr. Moul discusses the adjustments he makes to his dividend yields. This includes an adjustment to reflect the time value of money. The necessity for such an adjustment is refuted in a study by Richard Bower of Dartmouth College. Bower acknowledges the timing issue but he demonstrates that this does not result in a biased required rate of return. He provides the following assessment:[24]

> "... authors are correct when they say that the conventional cost of equity calculation is a downward-biased estimate of the market discount rate. They are not correct, however, in concluding that it has a bias as a measure of required return. As a measure of required return, the conventional cost of equity calculation (K*), ignoring quarterly compounding and even without adjustment for fractional periods, serves very well."

Q. PLEASE CRITIQUE MR. MOUL'S DCF GROWTH RATE OF 5.50%.

A. Mr. Moul's growth rate is excessive because his assessment of growth for the electric utility companies is extremely distorted and biased. In Schedules 6 and 7, Mr. Moul provides sixteen alternative measures of growth he claims to have reviewed in arriving at his 5.50% growth rate. He totally ignores five of the measures (Value Line historic 5- and 10- year DPS and EPS growth as well 5-year cash flow per share growth) because, in his opinion, they are too low. Of the remaining eleven, only one is as large as 5.50% and the average of these figures is only 4.10%. He claims to have relied primarily on 5-year projected EPS growth rates. However, even Mr. Moul's average forecasts of Wall Street analysts are only 4.90% for the electric utility group. And he clearly has ignored projected DPS growth, which is 2.94% for his group. This is significant because the cash flows in the DCF model are dividends and not earnings.

In short, in arriving at his 5.50% DCF growth rate, Mr. Moul appears to have

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[24] See Richard Bower, The N-Stage Discount Model and Required Return: A Comment," Financial Review (February 1992), pp 141-149.

selectively relied on the projected EPS growth rate results from Wall Street analysts and *Value Line*.

Q. PLEASE REVIEW MR. MOUL'S RELIANCE ON ANALYSTS' AND *VALUE LINE*'S PROJECTED EPS GROWTH RATE ESTIMATES.

A. Mr. Moul has relied excessively on the EPS forecasts of Wall Street analysts and, in this case, he has given far too much weight on *Value Line*'s average projected EPS growth rate to gauge growth for his DCF model. It seems highly unlikely that investors today would rely excessively on the forecasts of securities analysts and *Value Line*, and ignore historical growth, in arriving at expected growth. In the academic world, the fact that EPS forecasts of securities analysts are overly optimistic and biased upwards has been known for years. In addition, as I show below, *Value Line's* EPS forecasts are excessive and unrealistic.

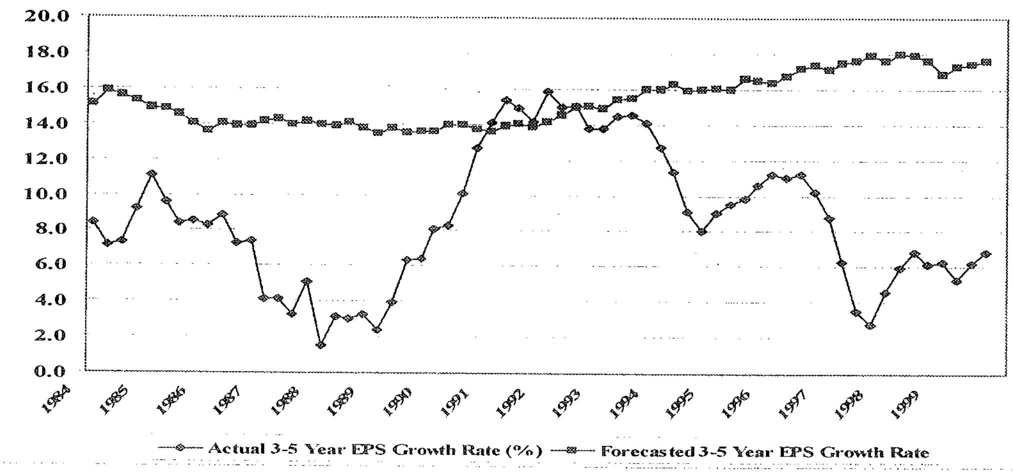
Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street Analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph only (1) covers forecasted and actual EPS growth rates through 1999, and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

The following example shows how the results can be interpreted. As of the first quarter of 1995, analysts were projecting an average 3-5-year annual EPS growth rate of 15.98%, but companies only generated an average annual EPS growth rate over the next 3-5 years of 8.14%. This 15.98% figure represented the average projected growth rate for 1,115 companies, with an average of 4.70 analysts' forecasts per company over the 20 year period covered by the study. The only periods when firms met or exceeded analysts' EPS growth rate expectations were for six consecutive quarters in 1991-92 following the one-year economic downturn at the turn of the decade.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates 1984-1999



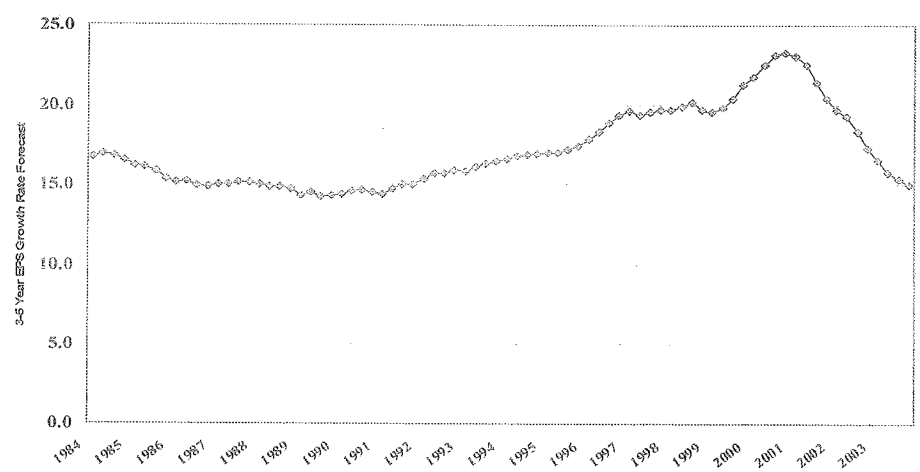
Source: J. Randall Woolridge.

Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the Elliott Spitzer investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1985 to 2004. In this graph, no comparison to actual EPS growth rates is made and hence there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2004 and, since companies are not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms.[25] Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995, and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted growth has since declined to the 15.0% range.

Mean Analysts' 3-5-Year Forecasted EPS Growth Rates
1985-2004



Source: J. Randall Woolridge.

While analysts' EPS growth rate forecasts have subsided since 2000, these results suggest that, despite the Elliot Spitzer investigation and the Global Securities

[25] The number of companies in the sample grows from 2,220 in 1984, peaks at 4,610 in 1998, and then declines to 3,351 in 2004. The number of analysts' forecasts per company averages between 3.75 to 5.10, with an overall mean of 4.37.

Settlement, analysts' EPS forecasts are still upwardly biased. The actual 3-5 year EPS growth rate over time has been about one half the projected 3-5 year growth rate forecast of 15.0%. Furthermore, as discussed later in my testimony, historic growth in GNP and corporate earnings has been in the 7% range. This observation is supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. 'You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.'
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[26]

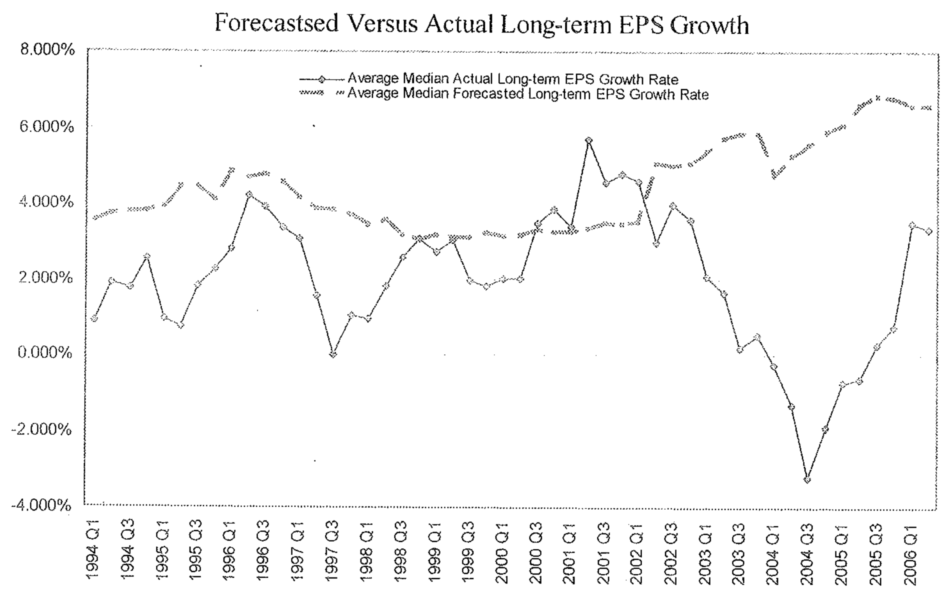
Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS LIKEWISE UPWARDLY BIASED FOR ELECTRIC UTILITY COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for a group of electric utility companies, I conducted a study similar to the one described above using a group of thirty-two electric utility companies. The projected EPS growth rates, which were in the four percent range in the 1990s, have increased over

[26] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

the past five years to the six percent range today. Actual EPS growth has been volatile, and consistently below projected EPS growth rates. Over the entire period, the average quarterly projected and actual EPS growth rates are 4.41% and 1.99%, respectively. It also appears that analysts tend to miss downturns in EPS growth. Overall, the results here are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for electric utility companies.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates
Electric Utility Group
1990-2006



Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line*

Investment Analyzer. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,611firms. The average projected EPS growth rate was 16.1%. This is incredibly high given that the average historical EPS growth rate in the US is about seven percent! Equally incredible is that *Value Line* only predicts negative EPS growth for thirty companies. That is one percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,611 Firms	16.1%	30	1.1%

To put this figure in perspective, I screened the 2,611 firms with 3-5 year growth rate forecasts to see what percent had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 1,613 of the 2,613 companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings as the economy and businesses have rebounded from the recession of 2001. These results, shown in the table below, indicate that the average historic growth was 9.40% and *Value Line* reported negative historic growth for 405 firms which represents 25.1% of these companies.

Historical Five-Year EPS Growth Rates for Companies with Value Line 3-5 year EPS Growth Rate Forecasts

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
1,613 Firms	**9.40%**	**405**	**25.1%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that analysts at *Value Line* are similar to the analysts at Wall Street firms and view future earnings through 'rose-colored' glasses and provide overly-optimistic forecasts of future growth.

Q. PLEASE REVIEW MR. MOUL'S SO-CALLED LEVERAGE ADJUSTMENT.

A. Mr. Moul's DCF results include a so-called leverage adjustment. Mr. Moul claims that this is needed since (1) market values are greater than book values for utilities, and (2) the overall rate of return is applied to a book value capitalization in the ratemaking process. This adjustment is erroneous and unwarranted for the following reasons:

(1) As noted above, the market value of a firm's equity exceeds the book value of equity when the firm is expected to earn more on the book value of investment than investors require. As such, the reason that market values exceed book values is that the company is earning a return on equity in excess of its cost of equity;

(2) Financial publications and investment firms report capitalizations on a book value and not a market value basis.

(3) Mr. Moul makes the claim that the market value – book value adjustment was based on

the research of Nobel prize winners Modigliani and Miller. Mr. Moul was asked in Interrogatory OUCC-7-221 to identify exactly where one could find his proposed adjustment in the research of Modigliani and Miller. He was unable to do so.

(4) In OUCC-7-220, Mr. Moul was asked to provide what other regulatory commissions have adopted his leverage adjustment. Despite having proposed the adjustment in many cases, only the Pennsylvania Public Utility Commission has made any adjustment based on Mr. Moul's market-value-book value divergence argument.

Q. DOES MR. MOUL'S LEVERAGE ADJUSTMENT PRODUCE LOGICAL RESULTS?

A. No. In addition to being erroneous and unwarranted, the adjustment is illogical because it works to increase the returns for utilities that have high returns on common equity and decrease the returns for utilities that have low returns on common equity.

In the graphs presented above, I have demonstrated that there is a strong positive relationship between expected returns on common equity and market-to-book ratios for public utilities. Hence, in the context of Mr. Moul's leverage adjustment, this means that (1) for a utility with a relatively high market-to-book (e.g., 2.5) and ROE (e.g., 12.0%), the leverage adjustment will increase the estimated equity cost rate, while (2) for a utility with a relatively low market-to-book (e.g., 0.5) and ROE (e.g., 5.0%), the leverage adjustment will decrease the estimated equity cost rate. Such an adjustment defies logic because you are increasing the estimated equity cost rate for the high market-to-book utility and decreasing the estimated equity cost rate for the low market-to-book utility. Therefore, the adjustment will result in even higher market-to-book ratios for utilities with relatively high ROEs and even lower market-to-book ratios for utilities with relatively low ROEs.

Q. FINALLY, PLEASE ADDRESS MR. MOUL'S CRITICISMS OF THE DCF MODEL.

A. Between pages 22 and 27 of his testimony and in Appendix D, Mr. Moul criticizes the use of the DCF model to estimate equity cost rates in today's market conditions and makes an adjustment for one of these factors. His criticisms can be summarized as follows: there are problems in using the DCF model in this case because (1) the share prices of utility stocks have risen due to takeover speculation; (2) the assumptions used in the theoretical derivation of the DCF model; (3) in conjunction with the DCF assumptions, which include the assumption of a constant P/E ratio and the fact that P/E ratios are not constant but change over time, and (4) the DCF model produces insufficient earnings when market-to-book ratios are above 1.0. I will address these issues in order.

(1) Problems with the DCF model due to rising prices attributed to takeover speculation

The share prices of utilities have increased in recent years for a number of reasons, part of which may be the possibility of being acquired. The fact that prices rise simply means that either expected returns have changed or that there has been a